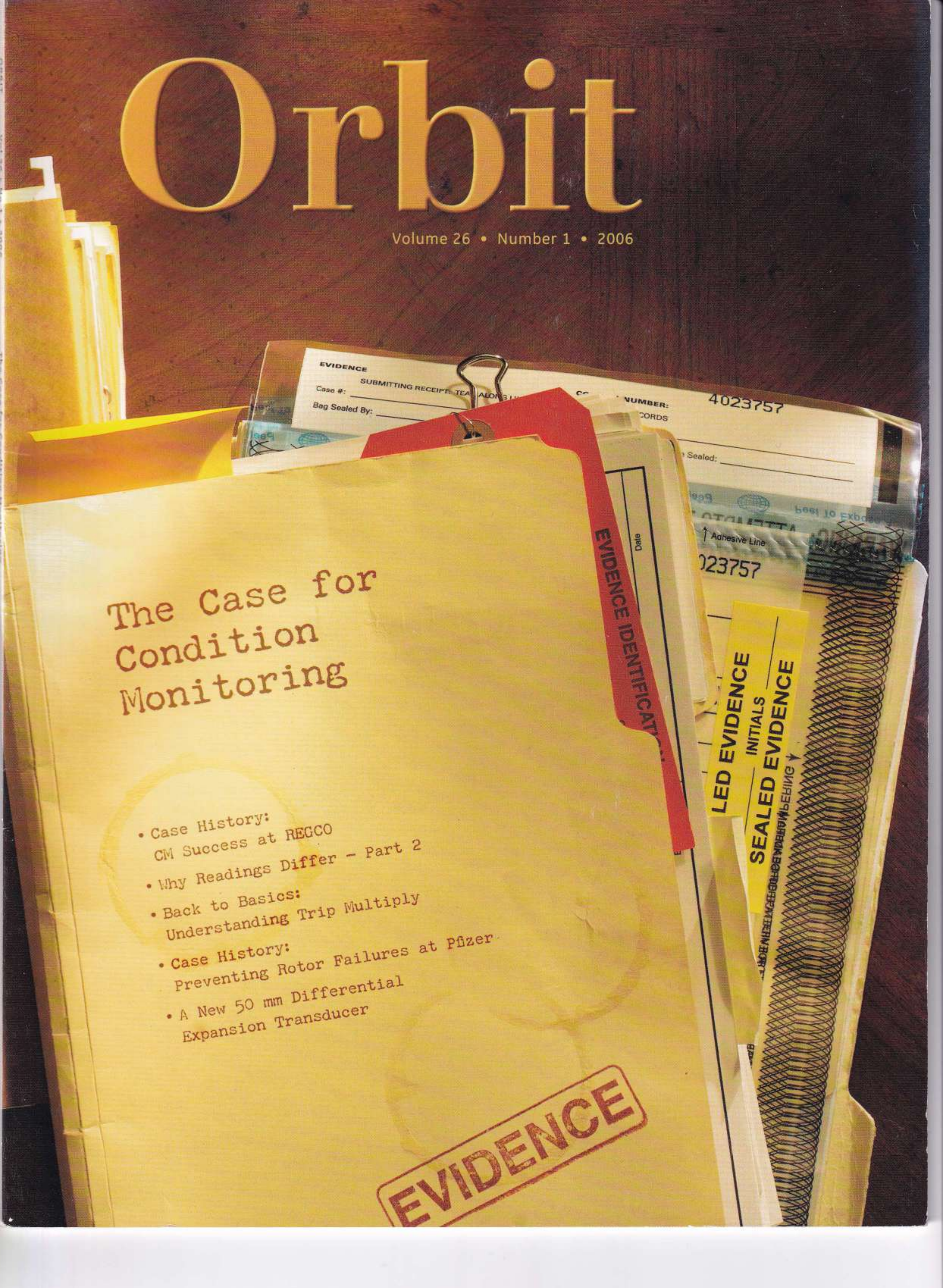
Orbit

Volume 26 • Number 1 • 2006



The Case for Condition Monitoring

- Case History: CM Success at REGCO
- Why Readings Differ – Part 2
- Back to Basics: Understanding Trip Multiply
- Case History: Preventing Rotor Failures at Pfizer
- A New 50 mm Differential Expansion Transducer

Orbit

A Technical Publication for Advancing the Practice of Operating Asset Condition Monitoring, Diagnostics, and Performance Optimization

Vol.26 No.1 2006

Publisher:
GE Energy

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Circulation:
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Printer:
Banta Publications Group

Welcome to our first ORBIT for 2006. Although the cover for this issue is admittedly a bit tongue-in-cheek, it reflects a serious concern faced by many of our readers: the challenges faced in creating a compelling financial case as they justify to their executive management the value of condition monitoring and reliability/maintenance programs.

I frequently peruse a number of publications devoted to reliability and maintenance topics. Lately, it seems that just about every one of them is beating the same drum. Editorials, articles, and letters from subscribers all bemoan the difficulties of engaging with executive management — some feeling as though they are in a daily fight for their very existence. But there is a common denominator that threads through all of these: the language of technology doesn't go very far with executives. Like it or not, executives speak the language of finance, because that is what they are paid to do — manage the health of the business. To be successful, then, maintenance and reliability professionals must be bilingual: technology with their peers, economics with their management.

The primary objective of ORBIT has always been to educate our readers. Today, however, that increasingly means expanding beyond our historical focus on machinery monitoring and diagnostics to encompass the larger picture of how practitioners can optimize their overall reliability and maintenance programs — in ways that are meaningful to CEOs. No, we haven't abandoned the case histories and application articles for which the magazine is best known, nor will we depart from the deep technical detail that such articles require. However, you will see us supplementing our content with articles that address more fully the challenges of optimizing overall reliability and maintenance practices. In fact, our July issue will be devoted substantially to this topic.

As always, we will continue to arm you with practical advice and proven methodologies that make the practice of your profession easier. And, we hope that through the case histories and "Synopsis of Savings" that we regularly feature in these pages, we likewise make your engagement with executive management easier by showing how others in your shoes have quantified and justified their own programs, measuring success in terms their executives can relate to.

In closing, please remember that it is your feedback that is the single most important part of helping us improve ORBIT so that it continues to meet your needs. If you haven't already done so, please take a moment to participate in our reader survey at www.ge-energy.com/orbitsurvey.

ORBIT is published three times per year by GE Energy

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Printed in the USA

Over 40,000 copies distributed worldwide

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GEA-14391

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Coming in the next issue of ORBIT...

"Reliability — Changing the Game"

- Back to Basics: Understanding K/M
- Unlocking Your Enterprise's Potential Through Improved Reliability
- Case History: 25 Years of Condition Monitoring Experience at E.ON.

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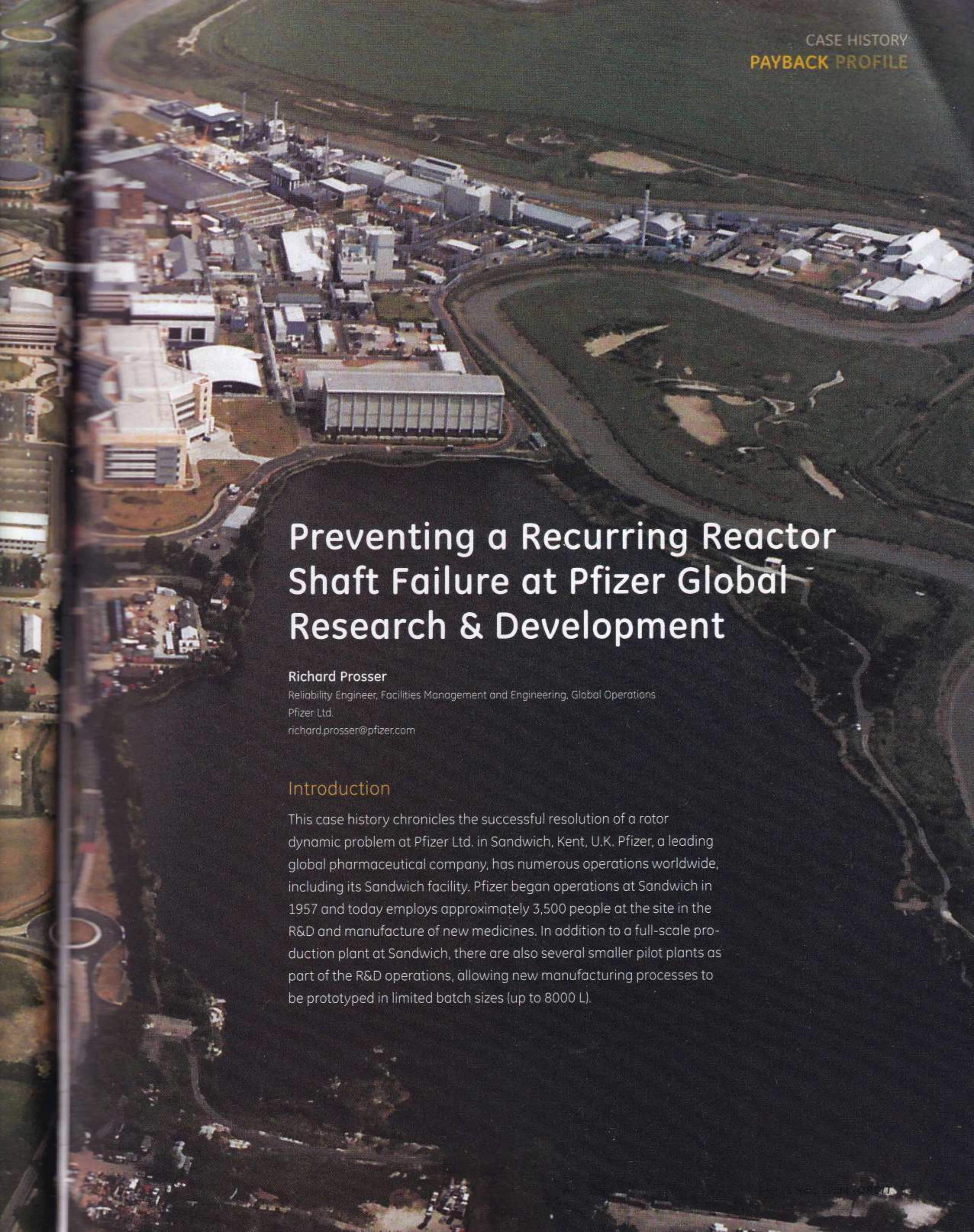

Preventing a Recurring Reactor Shaft Failure at Pfizer Global Research & Development

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Introduction

This case history chronicles the successful resolution of a rotor dynamic problem at Pfizer Ltd. in Sandwich, Kent, U.K. Pfizer, a leading global pharmaceutical company, has numerous operations worldwide, including its Sandwich facility. Pfizer began operations at Sandwich in 1957 and today employs approximately 3,500 people at the site in the R&D and manufacture of new medicines. In addition to a full-scale production plant at Sandwich, there are also several smaller pilot plants as part of the R&D operations, allowing new manufacturing processes to be prototyped in limited batch sizes (up to 8000 L).

Hydrogenation Reactor R23

Hydrogenation is a chemical reaction involving the attachment of hydrogen atoms to carbon atoms. This reduces the number of unsaturated bonds on each carbon atom and is used in many petrochemical and pharmaceutical manufacturing processes. The chemical reaction requires a hydrogen-rich environment and takes place in a special reaction chamber involving mechanical agitation.

In Pfizer's pilot plant, hydrogenation is done in a reaction vessel known as R23. Although the pilot plant is designed to run much smaller batches than production-scale processes, it is not without its own economic impact, and R23 plays a particularly important role. The economics that mandate monitoring such a machine stem from three primary factors as follows:

1. **Repair Costs**
   Table 1 summarizes the process conditions inside the reactor, necessitating highly specialized metallurgy (Hastelloy® C22) for the reactor components. Mechanical damage to the reactor results in particularly expensive repair costs due to this specialized metallurgy.

2. **Safety**
   Because pure hydrogen is used in hydrogenation, the process represents a highly flammable environment. As such, a reactor breach from mechanical failure has serious potential safety consequences such as a fire or explosion.

3. **Production Losses**
   The hydrogenation process is critical within the pilot plant. When it does not run, production schedules are significantly affected. Also, the product itself is extremely valuable. For example, a single 40 kg batch processed in the reactor can be worth many millions of dollars.

Hence, the justification for employing a condition monitoring program on such an asset is abundantly clear.

Table 1 –

Reactor R23 Process Conditions

Pressure	> 20 Bar g (290 psig)
Temperature	170° C (338° F)
Atmosphere	Hydrogen-rich (explosive)
Fluid	Corrosive

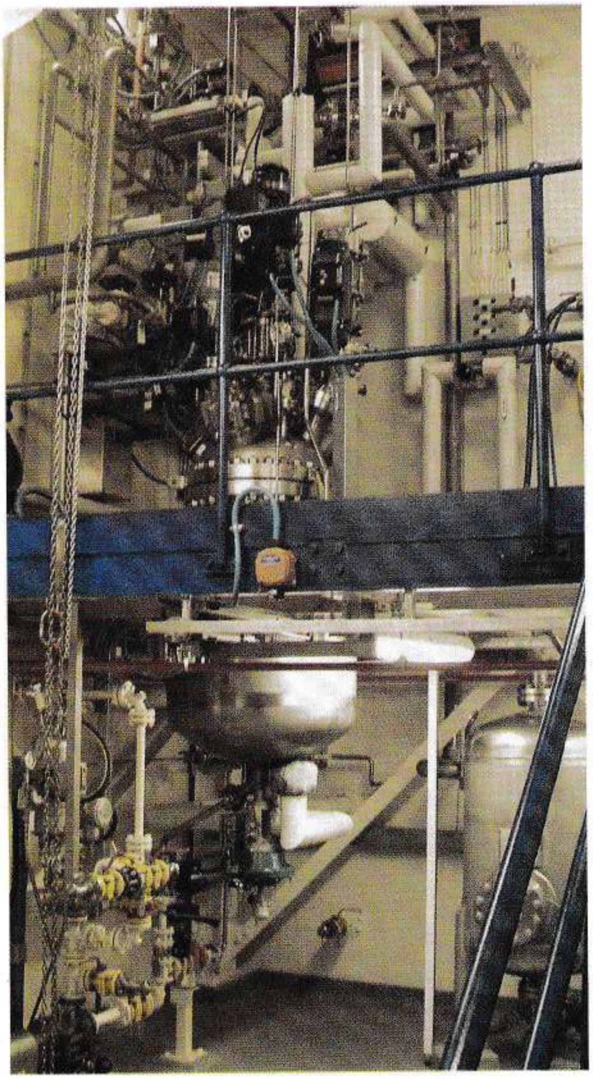


Figure 1 – **Hydrogenation Reactor R23 showing support gantry and access stair rail.**

Machine Construction

As shown in Figure 1, the reactor is suspended from a steel gantry rather than being rigidly affixed to the ground via footings. Figure 2 shows a cross-sectional diagram with the location of major components labeled. Noteworthy in the machine's design is the relatively long unsupported length (1685 mm or 66 inches) of agitator shaft protruding into the reaction chamber. The agitator rotor itself is not only long, it is relatively thin with a diameter of only 40 mm. This long, flexible, overhung design results in a machine that has rather "unforgiving" rotor dynamics, requiring the unit to be operated with great care. For example, operation of the agitator without fluid in the reactor vessel means that the rotor runs with almost no damping due to the very rigid support provided by the rolling element bearings. Also, because the agitator runs above its first balance resonance (i.e., "critical speed"), it must pass through this resonance when ramping to or from operating speed. Nameplate data on the machine lists the full speed as 1350 rpm and the critical speed as 550 rpm. Operation between 410 and 690 rpm is specifically precluded, and the machine is intended to rapidly ramp through its first critical on the way to or from operating speeds.

First Failure

As noted above, the rotor dynamics of R23 makes it vulnerable to failures unless operated with great care; namely, ensuring that the machine does not dwell in the region of its critical speed and that the machine always operates with sufficient fluid levels to submerge the agitator, providing the necessary damping. Although a route-based portable data collection instrument is used for many of the assets at Pfizer, the focus of such a program is generally to trend the degradation of components such as bearings, under the assumption they fail over a period of weeks or months. Sudden failures, such as caused by improper operating conditions, can occur in a matter of seconds or minutes, and require a different approach.

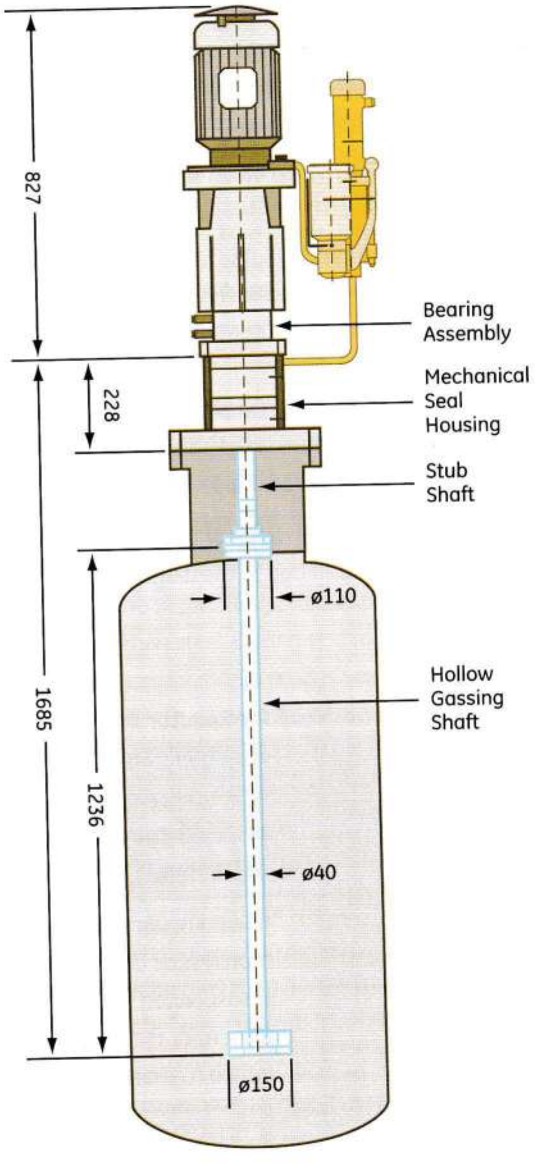


Figure 2 – **Cross-sectional view of R23 showing bearing locations and key dimensions (all dimensions in mm).**

The first of two shaft failures occurred during commissioning of the reactor and was attributed to improper ramp speed, allowing the unit to dwell too long at its balance resonance. Although the manufacturer repaired the rotor, achieving the correct operating parameters required intervention by Pfizer. The rotor behavior was mapped and a full resolution was achieved utilizing a Bently Nevada™ ADRE® system loaned to us by our local GE office.

Rather than relying solely on manual operator vigilance to avoid adverse operating conditions in the future, a fail-safe automated solution was sought. This was accomplished by making changes to the control system, altering the machine's ramping speed during starting and stopping, and ensuring that the machine passed through its resonance as quickly as possible.

Following this exercise, it was clear that an ADRE system would be a valuable addition to the diagnostic hardware regularly utilized by Pfizer; therefore, a system was purchased in November 2003.

Second Failure

In January 2004 a second shaft failure occurred, this time because the operators had inadvertently run the unit with inadequate fluid levels, resulting in insufficient damping of the rotor and another subsequent shaft failure.

It was recognized that some type of automatic protection was needed to address this separate failure mode (insufficient damping) and any other unforeseen failure modes, in addition to the control system ramping changes already described. Three alternatives were investigated as potential means to prevent R23 from operating when insufficient fluid (and corresponding insufficient damping) was present. These are summarized in Table 2.

Table 2 –

Alternatives Considered for Reactor Fluid Detection

1	Level Sensors	Although simple in theory and seemingly intuitively obvious, a level probe to ensure fluid was in the reactor was not the preferred solution. This was due to the congested nature of the reactor lid and the implications for periodic cleaning between batches that such a sensor would entail.
2	Seismic Vibration Transducers	It was known that operation of the reactor without fluid (i.e., insufficient damping) would manifest as dramatically increased vibration. However, as noted previously, the reactor is suspended from a steel gantry and subject to structural vibrations other than those from rotor dynamic excitation. As such, it was concluded that seismic vibration would not be a reliable detection strategy.
3	Shaft-Observing Vibration Transducers	Unlike casing-mounted seismic transducers, proximity probes directly observing the rotor measure the relative motion between the machine's housing and the rotor. This makes the measurement less susceptible to structural vibration from the gantry-style support of R23.

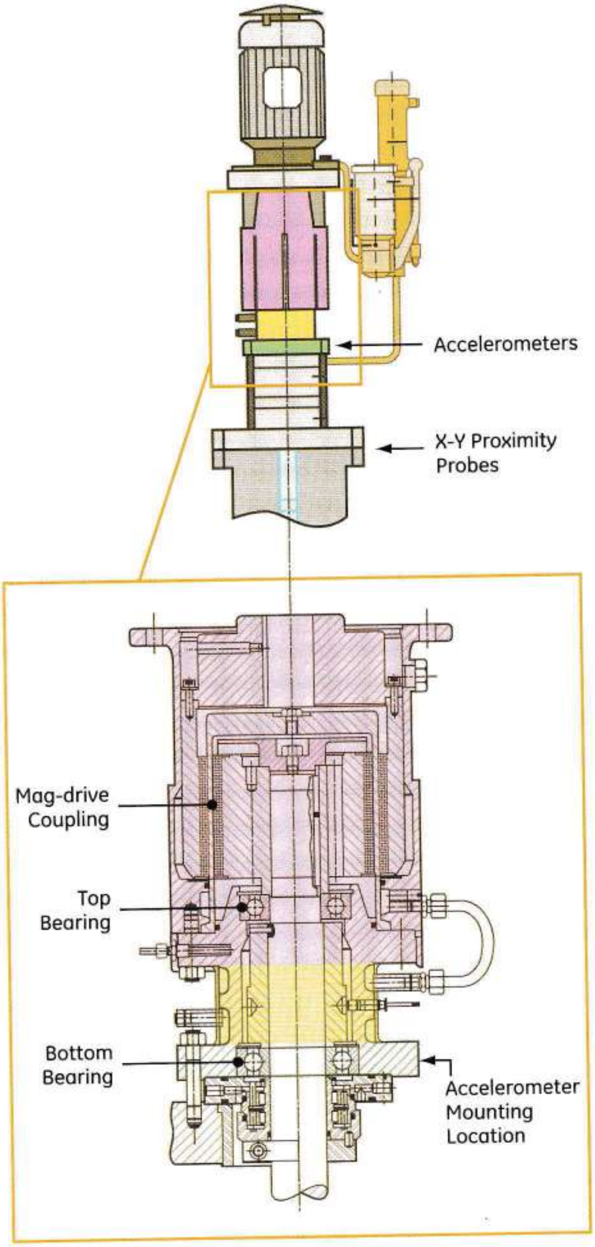


Figure 3 – **R23 cross-sectional view showing probe mounting locations in flange, accelerometer mounting locations, and bearing assembly details.**

Following feasibility assessments, option #3 (shaft-observing vibration transducers) was selected as the most promising approach. However, it was not without its own challenges for several reasons:

- The process conditions inside the reactor (see Table 1) were particularly aggressive, precluding the use of standard proximity probes.
- The observed shaft surface (Hastelloy C22) would require specially calibrated Proximitor® sensors.
- Mounting locations for the probes were limited; reactor design did not allow placing the probes at agitator mid-span where deflection was expected to be greatest. Instead, the probes would be mounted in the pressure vessel flange (Figure 3) where the stub shaft would be observed. This required application of the beam equation to determine the minimum amplitudes that would be required to provide reliable machinery protection.
- The pressure vessel flange was constructed of regular carbon steel. Drilling and tapping this flange to accommodate probes would allow the process fluids to contact the carbon steel. A suitable approach would need to be found that ensured the process fluids only contacted metallurgy known to withstand their corrosive effects.
- The agitator shaft has a very small diameter of only 40mm. This would require special attention to cross-talk between probes if an X-Y configuration were used, since the mounting flange would not allow for axial offset between the probes.
- The probes would need to adequately seal the process fluids inside the reactor chamber, ensuring that hydrogen could not leak, leading to a potential fire or explosion.

Following the above-mentioned engineering feasibility study, we elected to proceed with the proximity probes and a Bently Nevada 3500 series system to provide continuous monitoring and protection. While the proximity probes would be focused on protecting the machine from operation with insufficient damping (as manifest in excessive shaft deflection), we also elected to install two accelerometers on the agitator bearing housing (Figure 3) as a method for continuously trending bearing condition/degradation. The 3500 system would provide a relay contact allowing the control system to automatically ramp the machine to safe minimal speed whenever excessive shaft deflection was detected. In addition, 4-20 mA outputs would be provided to the control system, allowing overall vibration levels to be trended and correlated with process conditions and reactor operating speeds.

The GE Energy custom products team in Minden, NV, was enlisted to assist with design of special Bently Nevada proximity probes, able to meet the mechanical and environmental constraints enumerated above. The custom products team was able to take an existing design for ceramic-tipped 3300 series proximity probes that had been used extensively in petrochemical applications and modify it for our needs. To ensure the probe would be able to exhibit the same tolerance to process conditions as the reactor itself, the same metallurgy was used in the probe case as in the agitator (i.e., Hastelloy C22). An alumina-based ceramic tip was provided to hermetically seal the probe coil, preventing corrosion of probe internals and escape of process

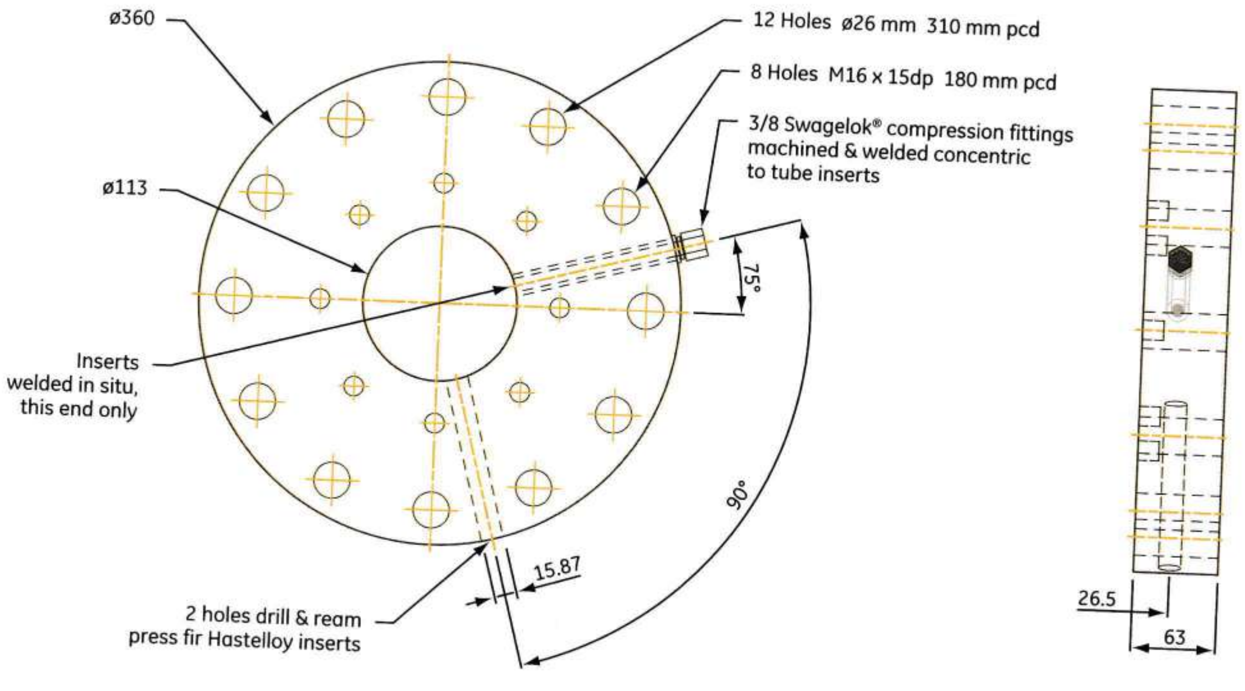

ø360
ø113
Inserts welded in situ, this end only
2 holes drill & ream press fir Hastelloy inserts
12 Holes ø26 mm 310 mm pcd
8 Holes M16 x 15dp 180 mm pcd
3/8 Swagelok® compression fittings machined & welded concentric to tube inserts
75°
90°
15.87
26.5
63

Figure 4 – **Machining details for accommodating proximity probes in reactor flange (all dimensions in mm).**

gases/liquids to the outside atmosphere. This was confirmed by completion of a helium leak test. Additionally, a sample of Hastelloy C22 was supplied to allow the factory to custom calibrate the Proximitor sensor to the unique metallurgy of the shaft target area. Finally, to ensure the carbon steel of the flange was protected from the corrosive process fluids inside the reactor, the probe holes were purposely bored oversize, allowing Hastelloy C22 sleeves to be inserted first, followed by the probes (figure 4).

THE SYSTEM WENT INTO SERVICE IN JULY, 2004, AND A MACHINE SAVE WAS RECORDED JUST ONE MONTH LATER UNDER THE EXACT SCENARIO ENVISIONED DURING DESIGN.

Results

The system went into service in July, 2004, and a machine save was recorded just one month later under the exact scenario envisioned during design: operating the reactor without sufficient fluid. While this dramatically validated the effectiveness of the system in protecting the machine from running with insufficient fluid levels, the system has also proven useful in detecting other conditions that would previously have led to failure.

For example, following a production run in May 2005, the 3500 monitoring system detected excessive rotor deflection and immediately returned the unit to a safe operating speed. However, there was sufficient fluid in the reactor. Operators attempted to reset the agitator, but it again entered alarm conditions. Some type of unknown forcing function was causing the machine to vibrate at approximately 300% of normal levels, and the decision was made to conduct further analysis to determine the source of this forcing function.

First, plant records were examined and it was learned that maintenance had recently been carried out on the motor. Therefore, this needed to be investigated and eliminated as the source of excessive vibration. Maintenance and balancing records showed nothing that might contribute to high vibration problems. Next, we collected slow-roll measurements from the agitator probes and compared with baseline data collected during commissioning of the rotor, following its failure in January 2004. This comparison allowed us to ascertain whether there was any distortion of the rotor. However, the measurements were within 3% of baseline data, strongly precluding rotor distortion as the source of the problem.

We then looked at the transient data collected using our ADRE system, allowing us to again compare current data with baseline data collected 18 months previous. This data is shown in Bode plot format in Figures 5a

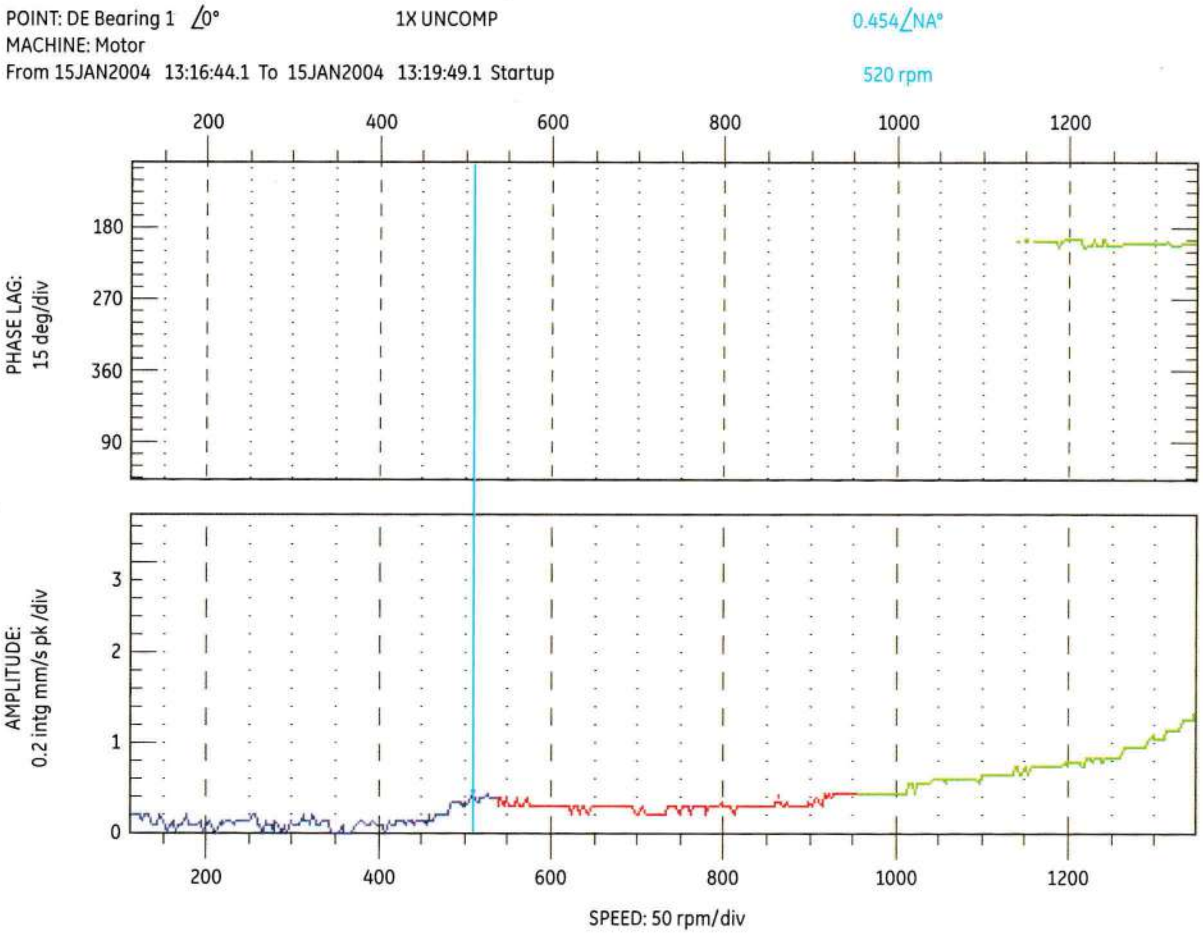


Figure 5a – **Bode plot showing baseline data collected in January 2004 with commissioning of new rotor. Note first balance resonance at approximately 520 rpm, as noted by cursor position, and amplitude climbing towards a second balance resonance somewhere well above 1200 rpm.**

and 5b. The dramatic change in resonant frequency was immediately apparent. As shown in Figure 5a, the baseline data of January 2004 showed the first balance resonance as approximately 520 rpm, very close to that predicted by the manufacturer. The plot shows this resonance is quite well damped, since the data was collected with appropriate fluid in the reactor. It also shows the vibration amplitude climbing towards a second balance resonance, somewhere above 1200 rpm. However, Figure 5b shows a clear resonance at approximately 780 rpm, as noted by the peak in amplitude, the classic 180 phase shift well below versus

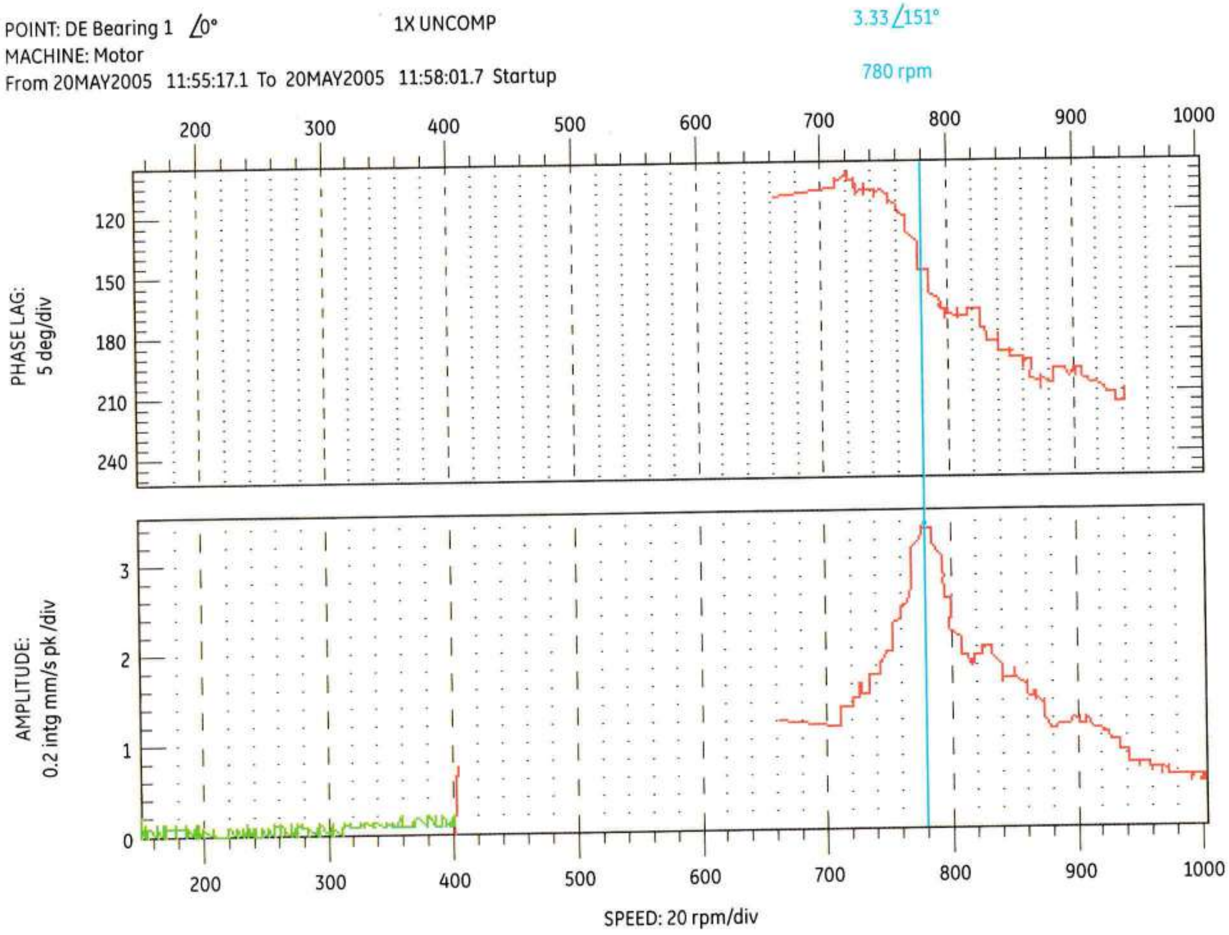


Figure 5b – **Bode plot showing data collected in May 2005, following shutdown due to high agitator vibration. Note the distinct resonance at 780 rpm, absent in previously collected baseline data.**

well above resonance, and the approximate 90 degree phase shift at resonance.

Basic rotor dynamic theory states a system's resonant frequencies (Ω_{res}) are determined by two physical parameters, system stiffness (K) and modal mass (M) via the relationship

$$\Omega_{res} = \sqrt{\frac{K}{M}}.$$

Thus, the observed shift in a balance resonance could only be explained by either a change in rotor system mass, a change in rotor system stiffness, or some combination of the two.

Because there was nothing to suggest a decrease in stiffness, and a decrease in mass would imply missing portions of the rotor, the most likely explanation was that mass had been added to the rotor system due to catalyst build-up, shifting the second resonance down to 780 rpm. The hypothesis of catalyst build-up on the agitator was further supported by the presence of small amounts of catalyst in the reactor vessel that had been noted during collection of slow roll data.

Consequently, we instructed the production department to run a full cleaning cycle on the reactor, resulting in further removal of catalyst build-up. Following cleaning, vibration data was again collected, which showed amplitudes and resonant frequencies comparable to commissioning values. The unit was thus deemed safe for return to normal operation.

Had the monitoring system not been in place, or if operators had simply relied upon some type of level indicator regarding reactor fluid levels, rotor damage would have likely ensued at great expense.

Conclusion

The monitoring system described in this case history was successful because we clearly understood the primary failure mode we were trying to address (insufficient damping), because we were equipped with good understanding of fundamental rotor dynamics, and because we employed the use of tools that allowed us to collect and analyze both transient and steady-state data. We thus designed a system that was tailored to our needs and reflected sound engineering principles. The economics of the asset made the decision to adopt a permanent monitoring approach relatively straightforward; however, the decision to use vibration monitoring, rather than another approach, required careful thought, as did the decision to use proximity probes rather than seismic transducers as the basis for determining whether sufficient damping was present. Ultimately, we employed seismic measurements for assessing bearing condition, and proximity probes for assessing rotor deflections, resulting in an approach that used the benefits of each measurement strategy appropriately.

The system has subsequently proven its value many times over, with the machinery saves more than eclipsing the cost of the monitoring system in the first year alone. Additionally, the system proved useful in detecting failure modes other than insufficient damping, as shown in this case history.

While we continue to use route-based periodic data collection for managing many of our assets, the events in this case history have enlightened many of us at Pfizer as to the benefits of continuous monitoring, the usefulness of the diagnostic methodologies, and appropriate application of our ADRE® system. All have been very sound investments for Pfizer.

Services Team Surpasses 4 Million Injury-Free Hours

At the beginning of 2005 (ORBIT Vol. 25 #1), we shared with our readers an important milestone achieved by our services team: three million hours without a single "OSHA-recordable" incident. One year later, we're pleased to share that the team's performance remains intact, having recently reached four million hours without an accident.

Our services team routinely works in difficult environments that require constant vigilance: refineries, offshore platforms, power generation facilities, wind turbine nacelles, and many others. As Jim Junker, general manager for the team puts it, "We have nearly 400 people on our team, many who work daily at customer sites in over 120 countries where extensive security and personnel safety precautions are required. In the industries we serve, you either demonstrate that you can perform the work safely, or you become a potential liability issue for our customers. In short, you don't get invited back. It's that simple."

We understand that when you invite a contractor such as GE onto your site, a safety "miss" reflects poorly on not only ourselves, but also on you, our customers. We're pleased that our services team offers both outstanding technical proficiency and the highest attention to safety. We're also extremely proud of the recognition the team has received within GE as the "safest" service organization in the entire company. This is particularly noteworthy, considering the size and breadth of GE, a company of more than 300,000 employees with numerous service organizations working in similarly difficult environments.

New Product Showcase

Highlighting New and Enhanced Condition Monitoring Products

3500/65 16-Channel Temperature Monitor

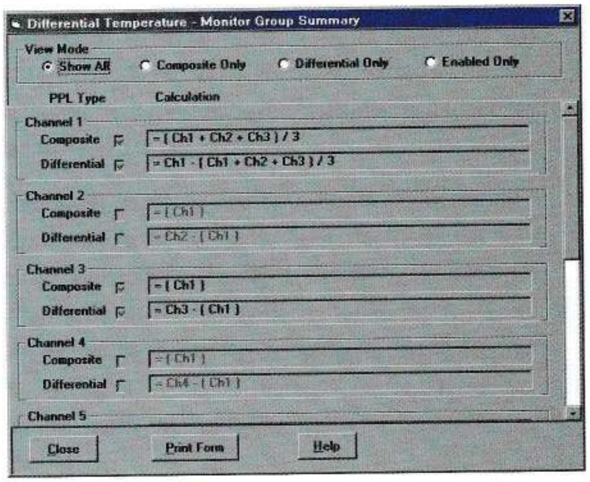
Improved channel density

Because rack space is often at a premium, modules with higher channel density can be very important in some applications. To help customers make the most of their available rack "real estate," we are pleased to offer the new 3500/65 temperature monitor. It provides a full 16 channels of high-integrity temperature monitoring in a single 3500 rack slot. The module supports 3- and 4-wire platinum, nickel, and copper RTDs, as well as E, J, K, and T isolated-tip thermocouples. Interfacing the monitor to process control systems, process data historians, and other applications is supported via the digital communications gateway in the 3500 rack, rather than through the use of analog recorder outputs.

Although the 3500/65 features a larger channel count than our 3500/60 and 3500/61 6-channel temperature monitors, it provides the conventional over/under, differential, and composite temperature measurements found in these other monitors. Composite measurements allow users to compute averages from a group of channels. Differential measurements allow the user to alarm on the difference between two directly measured points, or between a directly measured point and a composite measurement.

A typical application of this composite and differential functionality is on reciprocating compressor valve temperature measurements where the absolute valve temperature is often not as important as whether a particular valve's temperature deviates significantly from the average temperature of all the other valves in a cylinder group. For example, the 3500 configuration screen shown here illustrates a composite measurement that is the average of channels 1, 2, and 3. It also shows a differential measurement based on the deviation of channel 1 from this average.

You can learn more about this module by contacting your nearest sales professional or by visiting us at www.ge.com/energy and entering "172930" in our search engine, which will take you directly to the product's data sheet.



Differential Temperature - Monitor Group Summary

View Mode
● Show All ○ Composite Only ○ Differential Only ○ Enabled Only

PPL Type Calculation

Channel 1
Composite ☑ = (Ch1 + Ch2 + Ch3) / 3
Differential ☑ = Ch1 - (Ch1 + Ch2 + Ch3) / 3

Channel 2
Composite ☐ = (Ch1)
Differential ☐ = Ch2 - (Ch1)

Channel 3
Composite ☑ = (Ch1)
Differential ☑ = Ch3 - (Ch1)

Channel 4
Composite ☐ = (Ch1)
Differential ☐ = Ch4 - (Ch1)

Channel 5

Like our other 3500 series temperature monitors, the new 3500/65 monitor allows composite and differential alarming in addition to conventional over/under type alarms on individual channels.

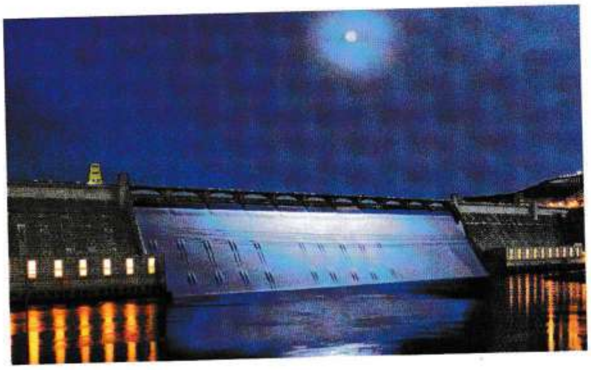
3500/46M Hydro Monitor

Now enhanced with Multi-Mode Capabilities

Hydro machinery, such as units that operate in pump-storage applications, exhibit distinctly different vibration characteristics depending upon whether the unit is operating as a motor-pump or a turbine-generator. Other units may operate as only turbine-generators, but varying flow, head, and load conditions can likewise yield distinctly different vibration characteristics. To address such machinery, a monitoring system capable of recognizing these distinct operating states is necessary, providing unique alarm setpoints for each characteristic operating mode.

While the 3500/46M Hydro Monitor Module is specifically designed to address hydro machinery, it did not previously support the multiple machine states needed by many hydro applications. The monitor has recently been enhanced to provide this important functionality, giving users eight configurable machine states for which independent alarm setpoints and time delays can be programmed. The result is a fully parametric monitoring strategy that is tailored to the individual operating modes of your hydro assets. This allows the 3500/46M to now address pump-storage applications in addition to conventional generation-only applications.

The addition of multi-mode functionality to the existing air gap and hydro radial vibration measurement capabilities in the 3500/46M monitor provides users with improved ability to protect and manage their hydro assets. By defining alarm levels for each relevant operating state, both spurious and missed alarms can be reduced because there is no longer a need to define an "average" machine state for which all alarms apply. Users can manually switch between operating states, or a signal (digital interface or contact closure) from the unit control system can be used to automatically switch the monitor between states, providing seamlessly coordinated control and monitoring. Operating states can be configured for virtually any user-defined set of conditions, alone or in combination, such as the following:



- machine speed
- machine load
- direction of rotation
- environmental conditions
- process variable levels

We have also introduced two new channel types to the 3500/46M, thrust position and acceleration, simplifying many installations by allowing a single module type to be used for all hydro measurements — air gap, radial vibration, seismic vibration (velocity and acceleration), and thrust position. The module allows any of these measurements to be used with or without multi-mode functionality, providing backward compatibility and allowing it to be used for spare parts requirements in existing installations. Learn more about the 3500/46M and our comprehensive portfolio of condition monitoring solutions for hydropower by contacting your local sales engineer, or by going online to www.ge.com/energy and entering "Hydro Condition Monitoring" in our search engine.

New 20 mm Air Gap Sensor

Extends Air Gap Measurement to Small- and Medium-Sized Hydro Generators

In August 2004, we released our 50 mm air gap sensor, designed to address large-diameter hydroelectric generators. We have recently augmented this offering with a new 20 mm sensor, allowing air gap measurements on small- to medium-sized generators where a reduced linear range is often necessary.

Air gap, a measure of the distance between the rotor and stator, is critical to the life of a hydroelectric generator and is one of the most important parameters for proactive condition monitoring. A non-concentric rotor and stator can cause various problems that may lead to generator damage, inefficiencies, or both. The air gap measurement enables operators to monitor rotor and stator shapes and positions, along with minimum and maximum air gap dimensions. This provides them with the information needed to remove a machine from service before serious damage occurs, such as magnetically induced overheating or rotor-to-stator rubbing. These capabilities have proven to reduce maintenance costs and increase availability, both important factors in today's hydroelectric operating environment where many machines have been thrust into far more demanding operating conditions than previously encountered, making condition monitoring a necessity rather than a luxury. Because these realities impact small- and medium-sized machines — not just large-diameter generators — a selection of sensor sizes to address all classes of hydro units is essential.

Designed to operate reliably in harsh environments, our 50 mm and 20 mm air gap sensors are able to maintain their accuracy in both the temperature and magnetic field extremes found in hydroelectric generators. The sensors are intended for use with our 3500 Series Machinery Protection System, which can be configured with special modules specifically for addressing vibration and air gap measurements on hydroelectric turbine-generators (see companion article on the 3500/46M module). When coupled with GE's System 1® Optimization and Diagnostic Software, users are able to view specialized air gap plots and other machinery condition parameters in real time. Learn more at www.ge.com/energy by entering "Hydro Air Gap" into our search engine.

Multiple Probes, Multiple Planes For Best Results

The air gap measurement is made by attaching anywhere from 4 to 16 sensors to the stator laminations at evenly spaced intervals on the same plane. The recommended number of sensors depends on the diameter of the rotor, per the table below. In order to fully monitor rotor/stator condition, dual mounting planes are recommended for the sensors — one near the top of the stator and the other near the bottom.

Rotor Diameter (meters)	Recommended Number of Probes
<7.5	4
7.5-12	8
12-16	12
>16	16

1900/65 Continues to Add Functionality

RTD and machine speed inputs now supported along with trip multiply capabilities

Introduced in 2005, our 1900/65 general-purpose equipment monitor filled an important condition monitoring niche for customers: the ability to apply cost-effective, high-integrity machinery protection to less-critical assets. Since introduction, we have steadily enhanced this 8-channel product. In the last issue of ORBIT, we highlighted the product's new Modbus® communications capabilities, allowing simplified and comprehensive communications with plant control and automation systems. Now, we are pleased to introduce numerous additional enhancements: support for RTD and speed inputs, additional communications options, and trip multiply/alarm inhibit functionality.

- **RTD inputs**

  2- and 3-wire RTDs can now be used for monitoring temperature in addition to the 1900/65's support for thermocouple and vibration inputs.
- **Enhanced vibration capabilities**

  Vibration channels can now be configured for acceleration, velocity, or Proximitor® inputs with support for both radial vibration and thrust position measurement types. In addition, new signal processing capabilities have been introduced, allowing the 1900/65 to be applied to selected reciprocating compressors when only basic casing vibration protection is required.
- **Speed Inputs now supported**

  A new channel type is available for proximity probe inputs, allowing machine speed to be measured along with vibration, thrust position, and temperature.

- **More communication options**

  Users' options for establishing Modbus communication links have been improved, with the 1900/65 now supporting your choice of Ethernet and RS232/RS485 serial links for this industry-standard protocol.
- **Trip Multiply/Alarm Inhibit**

  Another important enhancement includes the addition of Trip Multiply and Alarm Inhibit (see our companion "Back to Basics" article on page 26). These functions can be activated using inputs from contact closures or via the optional Modbus communication link.

Learn more from your nearest sales professional or by visiting www.ge.com/energy and entering "1900/65" in our search engine.

3300 XL 50 mm Proximity Transducer System

Designed specifically for differential expansion applications in aggressive steam environments

GE Energy's new Bently Nevada™ 3300 XL 50 mm transducer system is a highly robust and reliable replacement for all of our older 50 mm proximity probe systems — including the 7200 series 50 mm and the 130713 DE (Differential Expansion) transducer systems. It offers greater moisture resistance and a broader temperature range without compromising the linearity and accuracy required by differential expansion applications. The new system also delivers the longest linear range in our family of Bently Nevada proximity transducers, enabling displacement of up to 1.1 inches (1100 mils) to be addressed, and allowing it to be used wherever an extended-range measurement is required, whether for DE or other applications.

Turbine Differential Expansion — A Vital Measurement

Large steam turbines, and certain gas turbines, exhibit non-uniform thermal growth rates of rotor and casing during machine startups and shutdowns. If not carefully monitored and controlled, excessive differential expansion can cause rotor and casing to rub, with catastrophic results. For this reason, the DE measurement is a critical component of a Turbine Supervisory Instrumentation (TSI) system, and operators depend on reliable DE information to safely start and stop their turbines.

The DE measurement poses particular challenges for a transducer system, since the measurement is made in environments where elevated temperatures and steam concentrations are present. The DE measurement also typically involves relative displacements that can exceed 1 inch (25.4 mm). This necessitates a transducer with an extended linear range. Further, turbines requiring a DE measurement are typically found in power generation applications where lost production revenues and contract penalties can be very expensive. As such, a transducer failure has serious economic consequences

Transducer Color Codes Help Eliminate Installation Errors

Bently Nevada™ proximity transducer systems from GE Energy incorporate three basic components:

1. Probe and integral cable
2. Extension cable
3. Proximitor® sensor

Probes are available in a variety of tip sizes and case sizes, and for facilities that use multiple sizes of probes, it can be easy to mismatch components from different systems since they may look very similar. To assist our customers, we introduced the following color-coding system in the mid-1990s for use on many of our most popular proximity probe systems. Used on probes, cables, and Proximitor sensors, it allows the correct components to be easily identified by color, helping to eliminate the likelihood of mismatching.

SYSTEM	COLOR
3300 XL 5 & 8 mm	Blue
3300 XL 11 mm	Purple
3300 XL 25 mm	Lime Green
3300 XL 50 mm	Brown
7200 5 & 8 mm	Light Yellow
NSv and RAM	Gray
16 mm HTPS	Orange
REBAM®	White

because it precludes the operator from being able to start the machine — and installation of spare or redundant transducers are often not practical.

Combined, these factors require a transducer system that is highly reliable and robust, is impervious to moisture and elevated temperatures, and delivers the necessary accuracy over an extended linear range. All of these considerations were addressed in the development of the new 3300 XL 50 mm transducer system, and we are pleased to offer this outstanding product to our customers. You can learn more by contacting your local sales professional or by visiting www.ge.com/energy and entering "174014" in our search engine, taking you directly to the product's datasheet.

GE
Energy

Save the Date!

GE Energy's 2006 Optimization and Diagnostics Software Users' Conference

With more than 3000 active installations of our System 1® condition monitoring platform and our performance monitoring software packages, we're pleased to announce the creation of a forum that allows our users to share their experiences with one another and with us. Join us in Atlanta, June 27-29, at the Marietta Hyatt Regency Suites for **Unlocking the Potential: 2006 Optimization and Diagnostics Software Users' Conference**.

Designed to facilitate sharing and networking with your peers from around the world, you'll learn about:

- Getting more from your software through powerful educational sessions with product tips and tricks
- How other users are applying their systems in new and innovative ways
- Why and how customers are integrating their systems with other reliability, control, maintenance, and business applications
- Upcoming product upgrades and enhancements

The conference will feature breakout sessions, allowing you to personalize the agenda to your specific product(s) and needs. It's also an opportunity for you to meet the people behind the software, giving you direct access to our developers, and giving us important feedback on how we can continue to improve our products to meet your needs.

To learn more or to register, visit us online at www.ge-energy.com/unlock. You can also call (+1 775.215.2292) or use the Reader Service Card attached to this issue of ORBIT to obtain additional information.

imagination at work

System 1® Software Version 6.0

More reasons to rely on System 1 as your condition monitoring platform for every asset

System 1 software is, without question, the most powerful platform we have ever released for comprehensive condition monitoring. It combines support for numerous data sources (online and offline systems, process data, CMMS data), a highly flexible client/server architecture, extremely powerful diagnostic capabilities, and a modular design that allows customers to configure their system with only those features that are relevant to their specific asset types.

We are pleased to announce the release of version 6.0, which introduces many powerful new capabilities. However, because System 1 software has so many powerful features, it can also be complex. For this reason, version 6.0 gives special attention to making the product easier to use and easier to deploy. This translates to a faster learning curve for your people as well as simpler implementation in your plant's IT environment.

System 1®
Optimization and Diagnostic Platform
P/N: 174517-01
Version: 6.0 | Disk 1 of 4
Patents: 6,421,571; 6,934,696
1631 Bently Parkway South
Minden, NV 89423 USA
+1 775.782.3611
GE
Energy
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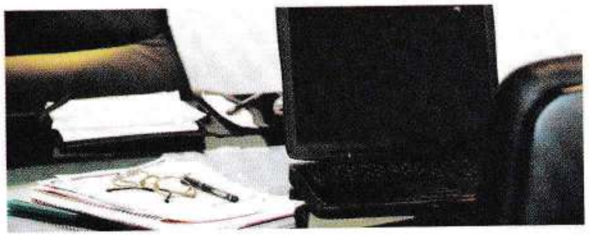
In the following table, we have summarized the numerous additions made to the software since the Second Quarter 2004 issue of ORBIT when we last updated our readers with the release of version 5.0. In the nearly two years since that last update, the product has continued to evolve substantially.

What's New in System 1 version 6.0?

FEATURE	BENEFIT	DESCRIPTION
Improved partitioning and licensing	Easier license administration for users, fewer system expansion restrictions, simpler menu options, and easier to purchase only what you need	Users now pay for only what they need, with a far more scalable architecture and pricing structure. It is now possible to purchase only the functionality relevant to specific machine types or applications (such as Hydro or Reciprocating Compressors), and to purchase only the number of points needed to address the application — without constraining the ability to economically add more points and machine types in the future. Most customers will also benefit from fewer restrictions on the number of display and configuration clients they can install under a single license.
File-based configuration	Faster, easier point configuration	For systems with a large number of points, previous versions of System 1 software required the use of individual configuration screens for each point. The introduction of file-based configuration capabilities now allows users to configure large numbers of points more rapidly. Configuration data can be imported/exported as a "flat file" to a Microsoft® Excel® spreadsheet, allowing fields to be pre-populated, data to be cut and pasted, points to be easily replicated, and many other options. New query/report tools allow users to search for only those points and parameters to be changed (such as the lower alarm levels for all pressure points) and export only those points and configuration parameters to Excel. New mapping tools are also present, making it much easier to map configured instrument points to their corresponding enterprise locations.

FEATURE	BENEFIT	DESCRIPTION
Improved rule-building capabilities	Faster, easier rule configuration and verification	New tools dramatically reduce the time it takes to build and verify rules by making it easier to find the applicable operands for a given rule and by reducing the number of operands that need to be mapped to each rule. New reporting utilities have also been introduced, allowing you to rapidly identify missing or incorrect details in rule configuration data.
Improved support and diagnostics for IT professionals	Faster, easier, and more comprehensive abilities to monitor System 1 utilization and operation	A Systems Management Console (SMC) is now available, providing users with tools for analyzing database, memory, and disk usage statistics, security settings, estimated time remaining until storage devices are full, overall "health" of the System 1 installation, and many other powerful utilities frequently requested by customers' IT departments.
State-based monitoring and diagnostics	Improved equipment diagnostic capabilities and cause/effect determination	Identical in concept to the state-based monitoring in selected 3500 modules (see page 17), System 1 now allows users to provide state-based variables in software. These states (such as machine on or off, unit at high or low load, etc.) can be used in a variety of ways, such as filtering data plots to only a specific operating state. States can also be used when designing custom rules in the Decision Support module of System 1 software.
Enhanced OPC interface	Faster, easier, and more comprehensive integration with other systems	In addition to support for OPC's Data Access (DA) specification, System 1 now supports the OPC Alarm & Events (A&E) specification. This provides users with improved ease and efficiency with which event-based data (such as alarms or configuration changes) can be exported to other systems.
Export to CSV/XML for plot to file/clipboard	Faster, easier data sharing between applications	Right-clicking on a plot now gives users the option to not just export a graphic of the plot, but to export the data points that comprise the plot in either CSV or XML format. This simplifies data export to other applications for advanced analysis, manipulation, plotting, correlation, reporting, and other functions.
Enhanced compressor map features	Faster, easier, more accurate compressor management	Performance maps now support an advanced smoothing algorithm for reactive and performance curves, enabling more accurate compressor performance measurements, improving compressor management and diagnostics.
Improved archiving	Faster, easier access to historical data	Archive databases can now be updated "in place", saving valuable time by eliminating the need to separately unzip and update archives before viewing.
Improved rule-testing capabilities	Faster, easier ability to verify the correct operation of rules before deployment	Historical test sessions can now be executed directly on RulePaks and run against both System1 historical databases and System1 archived databases. Users save time and testing costs by validating their RulePaks against known historical data first, before live deployment.
Multiple usability enhancements	Faster, easier, and more intuitive use; improved diagnostic precision	There are over one dozen usability enhancements introduced in version 6.0, ranging from the ability to tile plots in more formats, to the ability to exactly specify decimal digit precision when viewing data, to improved drag-and-drop capabilities for more types of objects in System 1 software.
Additional reciprocating compressor capabilities	Faster, easier, more accurate diagnostics for more machine and process types	There are over half a dozen significant enhancements for this machine type alone, allowing improved diagnostics and monitoring accuracy. For example, the software is now able to use dynamically changing process gas compositions in its calculations, important for machines that handle variable process streams.



Bernie Anger
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Investing in Innovation

Across all of our business, innovation is being stressed as our "ticket to the future." However, it is not innovation for innovation's sake. Rather, it is innovation with a purpose – to use our technological resources to meet customers' needs. As Technology Leader for our optimization and control business unit, I'm responsible for leading a team of nearly 600 highly skilled engineers to do just that: meet customer needs using technological innovations.

Although I have been in my new role only since last October, my entire team has impressed me as having a culture with deep roots in innovation. Coupled with this culture of innovation are active customer partnerships and a comprehensive approach to problem solving. This gives me tremendous optimism regarding our ability to make a difference with customers and continue to be known as the leaders in our field.

As we enter 2006, I felt it was appropriate to underscore for our ORBIT readers this ongoing commitment to innovation by sharing some of our product development activities and initiatives. At a macro level, these include:

- A 20% spending increase in new product programs relative to 2005.
- Incremental and step-change improvements to sensors, monitors, systems, and software platforms.
- Strong ongoing support and enhancements to ensure our solutions work with machinery and controls from *all* OEMs.
- Increased investment in fundamental science, encompassing sensing technologies, software algorithms, and materials research – in cooperation with GE's corporate research and development resources.

At a more detailed level, here is a preview of our 2006 activities related to transducers, monitors, and software.

Transducers

Condition monitoring and machinery protection all starts with transducers that can accurately measure process-critical parameters, typically in harsh environments. Three ways in which we will advance our sensing offerings this year are through *translations*, *combinations*, and *new platforms*.

As an example of a translation, the stator-mounted air gap measurement was a new application for us, allowing customers to measure rotor-to-stator clearance in hydro applications. To address some of the specific noise issues in generators with static exciters, the team had to develop an enhanced electronics package. When complete, they promptly *translated* these innovations to our other capacitive sensors.

From a combination perspective, our new High Temperature Velocity and Acceleration Sensor (HTVAS) combines both measurements in a single package. By performing this signal processing at the transducer, it eliminates the noise amplification issues that invariably result from trying to derive one measurement at the sensor, and another back at the monitor. As a result, HTVAS provided a creative and simple solution to a known problem.

We take this same approach when working on new platforms. By combining the resources and domain expertise in our business with that of the Corporate Research Center, we fully expect to augment our ability to provide creative solutions to tough measurement problems. As a customer, you can expect to see improved versions of existing probes as well as probes able to address new applications/problems as a result of our 2006 efforts.

Monitors

A key challenge for us is to combine the excellent capabilities provided by our Bently Nevada™ 3500 platform in packages that allow customers to deploy condition monitoring and machinery protection more cost effectively and to a broader range of assets. To achieve this, we are working on three separate initiatives:

- Continuous enhancement to the 3500 platform, with new and improved monitor cards, allowing existing customers to augment installed systems and achieve greater value from their existing investments.
- Development of a next-generation set of monitors and systems with embeddable application knowledge that can be deployed across a broader range of assets in multiple industries. They will feature better integration with control systems, more flexibility when a highly distributed architecture is desired, smaller footprints, and reduced installation costs. Though still too early to talk publicly about the details of this offering, you can be assured that it will reflect our 50-year tradition of innovation and leadership in machinery protection and condition monitoring systems.
- Enhancements to our portable solutions — encompassing both our latest generation of ADRE® systems and our walk-around data collection systems.

Software

Enhancements to our monitoring hardware is always tightly linked to new capabilities in our software platforms, ensuring you benefit from system level enhancements. In 2006, we will be focusing on incremental improvements to our newest platforms, usability/reliability enhancements to our core platforms, and investments in packaged application content (such as System 1® RulePaks):

- Usability and ease of configuration will continue to be enhanced. Our software platforms have grown in capabilities at a very rapid pace during the past few years, and this growth has led to increased configuration complexity. 2006 will see a release cycle dedicated specifically to usability and reliability improvements. Our objective is to enhance both the initial installation/configuration experience and the day-to-day usability of the product.
- Our recently announced Kn$^{3™}$ product brings a new dimension of predictive capabilities for hard-to-model problems. Kn^3 utilizes a combination of neural network and genetic algorithms to characterize, monitor, and potentially control plant/process parameters. We will fine-tune this product to ensure its success in the application spaces where customers see potential benefit.
- With the release of System 1 version 6.0, we are introducing an enhanced set of tools for RulePak development. Kn^3 also provides highly configurable modeling capabilities. We plan on taking advantage of these platform-level capabilities to deliver specific RulePaks for some of your toughest problems, in a way that can be easily distributed and applied.

Although just a small snapshot of our activities in 2006, I hope it conveys to you our overriding purpose: to continue investing in innovation so that we remain focused as a business on solving your problems. Our legacy is that of a technology-focused business with a strong reputation for engineering excellence. That isn't changing. In fact, it's being enhanced. With our ongoing commitment to innovation, the extended reach of the broader organization to help us solve industry's toughest problems, and strong partnerships with our customers, I am confident that we can continue to grow as your partner of choice for asset reliability and performance.

Understanding Trip Multiply

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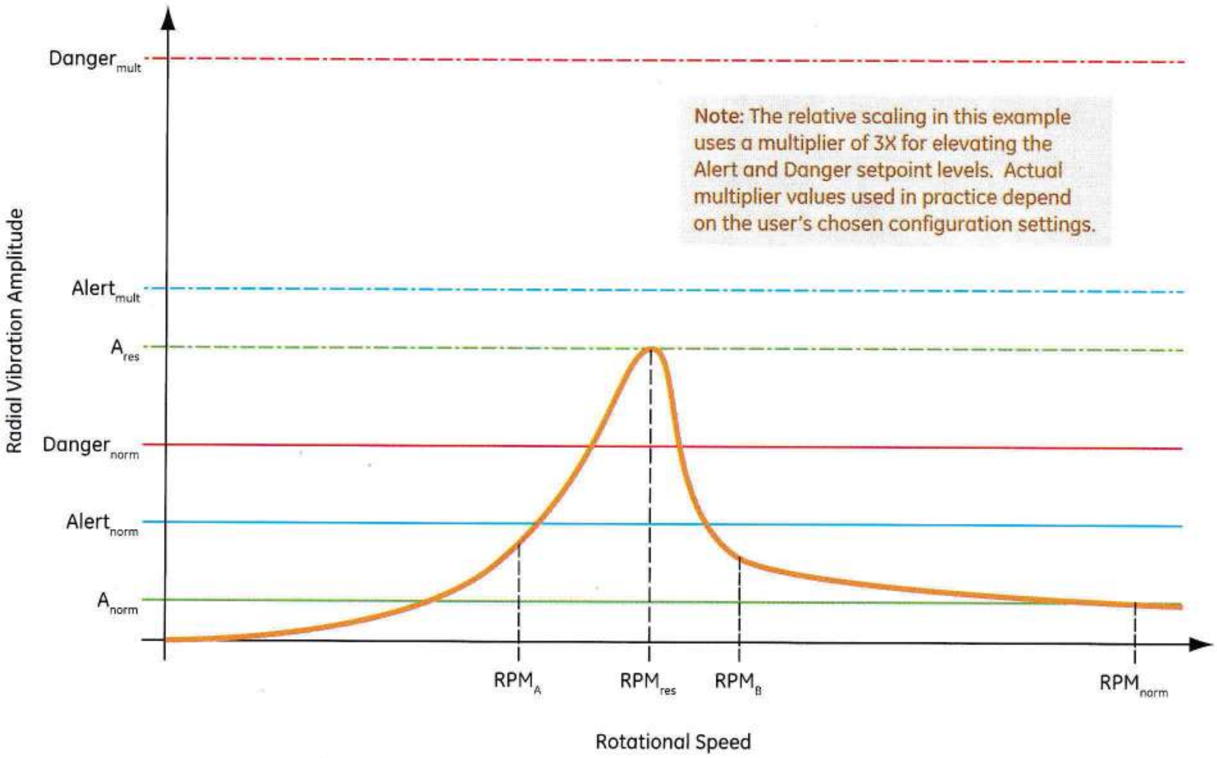
Trip Multiply and various inhibit features are included on many continuous monitoring systems. Within GE's Bently Nevada™ product line, these include the 3500, 3300, 7200, 1701, 1900/65, and numerous other systems released over the years. The purpose of Trip Multiply is to temporarily elevate alarm setpoints by a pre-configured multiple (usually 2X or 3X) based on a signal supplied by the machine's control system. This signal may be a contact closure from the machine control system, or in some cases, it may be via a digital communications link (for example, Modbus® protocol) on selected monitoring systems supporting such interfaces. The Trip Multiply function was developed specifically to address, and is intended only for, channels that monitor a machine's radial vibration while allowing the asset to ramp through regions of operation where a resonance (i.e., "critical speed") exists.

As shown in Figure 1 for a hypothetical machine operating above its first balance resonance, the peak vibration amplitude (A_{res}) occurs at its resonant speed (RPM_{res}). This amplitude is significantly larger than the amplitude A_{norm} encountered when the machine is running at its steady-state running speed RPM_{norm}.

Notice that while the Alert and Danger alarm levels ($Alert_{norm}$ and $Danger_{norm}$) established for the machine during steady-state operation are quite appropriate, they are too low to allow the machine to pass through its resonance. Unless the time delay chosen for the alarms exceeds the time during which the machine ramps through its resonance, the alarms will trigger.

Although these spurious alarms can be dealt with in three ways, as summarized next, Trip Multiply is the preferred method.

1. **Trip Multiply** can be used to temporarily elevate the alarm levels while the machine is in the RPM ranges corresponding to its resonance. This is shown in Figure 1 as the alarm levels $Alert_{mult}$ and $Danger_{mult}$, which would be in effect while the machine is between speeds RPM_A and RPM_B. Note that when the machine is outside these RPM ranges, its normal alarm levels are used. Notice also that Trip Multiply provides appropriate alarm levels at all stages of machine operation, ensuring it is never without shutdown protection.
2. **Inhibit** functionality can be used to temporarily suppress all alarming. However, there are various types of "inhibit" functions supplied with GE's Bently Nevada™ monitoring systems. Some, such as **Rack Inhibit**, essentially disable all functions of the monitoring system — not just alarms. Thus, this type of inhibit will essentially result in running completely "blind" with no indication of vibration levels whatsoever. Other types of inhibit, such as **Alarm Inhibit**, suppress alarms while allowing the vibration to still be displayed. Still other types of inhibit, such as **Special Inhibit**, are meant to address specific machine types and the need to suppress alarming in certain operating regions. It is important to note, however, that inhibit functionality is almost never intended to take the place of Trip Multiply functionality. Instead, it is normally reserved for situations such as performing maintenance on an instrumentation system while the machine is still running, eliminating the possibility of a false trip.
3. **Alarm Time Delays** can be used to ensure that a channel must continuously be above its alarm setpoint for a pre-established duration before the alarm will trigger. This can be useful on machines that pass very rapidly through a resonance. For example, if the starting sequence for a machine causes it to accelerate through its resonance region within 2 seconds,



Note: The relative scaling in this example uses a multiplier of 3X for elevating the Alert and Danger setpoint levels. Actual multiplier values used in practice depend on the user's chosen configuration settings.

Figure 1 – **Trip Multiply Example.**

and the alarm time delays are set for 3 seconds, the machine will safely pass through its resonance without generating spurious alarms. A disadvantage to this strategy, however, is that if a problem occurs with the starting sequence and the machine dwells longer than expected in its resonance region, an alarm will occur. Another disadvantage is that the starting sequence for some machines may not be rapid enough to accelerate through the resonance relatively quickly, necessitating unreasonably long alarm delays. Long alarm delays can in turn allow significant machinery damage to occur before an auto-shutdown ensues, particularly with malfunctions such as rubs or severe imbalance that can destroy internals the longer they go unchecked.

For the reasons mentioned above, we recommend the following when establishing a radial vibration alarm strategy:

- Establish alarm levels and time delays based on the machine's normal running speed(s) and load(s)
- If these levels and time delays do not allow the machine to pass through a resonance without generating spurious alarms, consider the use of Trip Multiply.
- Reserve inhibit functionality only for instrument maintenance or other occasions when the machinery protection needs to be knowingly bypassed. It should not generally be used in place of Trip Multiply.

Important: When using Trip Multiply, make certain the multiplied alarm setpoint does not exceed the dynamic range (which may be different than the full-scale range) of the monitor channel. Otherwise, the alarm will never trigger. For example, if a monitor channel has a dynamic range of 10 in/sec, a full-scale range of 2 in/sec, a normal danger setpoint of 1.5 in/sec, and a Trip Multiplier of 8X, this corresponds to a multiplied danger setpoint of 12 in/sec. The monitor will saturate at 10 in/sec and the multiplied alarm (12 in/sec) will not trigger.

Additional information on this topic can be found in Appendix I of *American Petroleum Institute Standard API-670, 4th Edition.*

Integrated Asset Management at REGCO, Thailand

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Introduction

In Thailand's power industry, the Rayong Electricity Generating Company (REGCO) has enjoyed excellent business success during the last decade. In large part, this success can be attributed to an outstanding plant availability record. This article discusses the mechanical and thermodynamic condition monitoring technologies used by REGCO to achieve and sustain this level of availability. In addition, several case histories are provided, illustrating actual machinery problems solved and the economic impact thereof.

About REGCO

In 1994, the newly commissioned Rayong Combined-Cycle Power Station became the first power project of the Electricity Generating Authority of Thailand (EGAT) to be privatized. Located in a resource rich and heavily industrialized region south of Bangkok, the facility was also the first independent power producer on the Thailand electricity grid. Over the past ten years, the company has not only maintained an uninterrupted electricity supply, it has been recognized with a special award each year since 1997 for exceeding availability targets.

The power station is a conventional combined-cycle design, with four blocks of 308 MW. Each block has two GEC Alstom Frame 9E gas turbines and one 102 MW steam turbine. The installed plant capacity is 1232 MW, with an "Equivalent Availability Factor "(EAF) averaging 88%. It presently delivers approximately 5000 GWh annually. The plant is fueled by natural gas, supplied from the Gulf of Thailand via a 430 km submerged pipeline from gas fields operated by Unocal and the Petroleum Authority of Thailand (PTT).

Operating Environment

Within Thailand, independent power producers (IPPs) operate under a long-term Power Purchase Agreement (PPA) with EGAT. The PPA is based on a cost-plus pricing strategy and consists of two components: A **capacity payment**, designed to cover fixed costs, and a **variable payment**, designed to cover variable generating costs such as fuel and maintenance. With Thailand's electricity demand growing at approximately 7% annually, this pricing strategy has been purposely designed to encourage investment in new generation infrastructure. Subsequently, the business focus is on plant *availability* and *capacity*.

The **capacity payment** is calculated based on a plant measurement known as "Dependable Capacity" (DC), which must be measured and audited regularly. It is independent of the actual amount of power generated. Under their original 20-year PPA agreement, REGCO is required to calculate their DC every six months using on-line performance testing. In contrast, other IPPs are required to declare their DC on a daily basis. This means that a poor DC for REGCO has repercussions for six-months, rather than just a few days. Consequently, REGCO has a compelling need for accurate and ongoing performance information, allowing them to detect and correct performance degradation at an early stage to minimize any financial impact.

The **variable payment**, as previously mentioned, is designed to cover actual generation costs such as fuel and maintenance. In REGCO's case, it additionally guarantees a minimum of 40% available capacity will be purchased annually.

With turbine-generator sets starting and stopping several times each week, REGCO identified a need for access to good machinery diagnostic capabilities early-on. Although GE's Bently Nevada™ continuous machinery protection systems were installed on many of the machines, the plant was reliant upon portable data acquisition equipment, such as an ADRE® system, for collecting and analyzing machinery data. They also contracted extensively with Bently Nevada™ machinery diagnostics engineers to provide regular onsite assistance with data analysis and root cause determination during startups and prior to overhauls.

In an effort to provide more continuous condition monitoring information, coverage of more asset types within the plant, and more self-sufficiency with regards to machinery diagnostics, the plant began to investigate the installation of a permanent condition monitoring infrastructure. Also, with the plant approaching ten years of age, the machinery had reached "middle age" and a permanent system was deemed crucial in perpetuating the outstanding plant availability track record that REGCO had achieved to date.

Combined, these factors have all been instrumental in REGCO's decision to invest in extensive condition monitoring and performance monitoring systems over the last five years. With the opportunity to renegotiate and extend the PPA in 2009, REGCO has an ongoing need for reliable information on the integrity of their machinery as well as real-time plant generation capability, allowing them to negotiate the most favorable PPA possible.

Choosing a Condition Monitoring System

As REGCO contemplated the selection of a condition monitoring system, the following criteria were identified:

- Service availability and quality
- Product capability and quality
- Ease of interfacing to REGCO's existing Bently Nevada™ machinery protection systems
- Ability to capture both transient and steady-state machinery data
- Scalable, distributed architecture, allowing simplified future expansion of the system

REGCO selected GE Energy's System 1® platform as the best fit for their needs, and it was installed on their critical machine trains in 2000. This entailed the retrofit of TDXnet communications processors to the plant's existing Bently Nevada machinery protection systems, and installation of System 1 software. In 2003, the installation was extended to include all essential pumps in the facility. This was accomplished using Trendmaster® Pro hardware to cost-effectively link the pumps to System 1 software.

Choosing a Performance Monitoring System

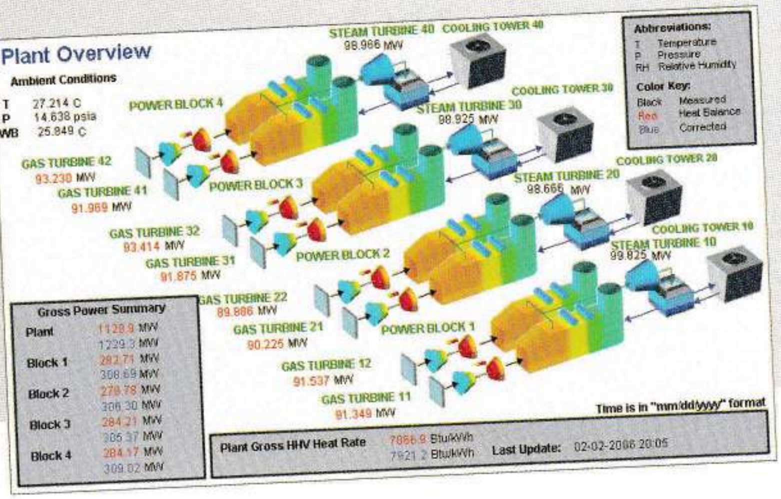
In early 2005, REGCO elected to expand their system further with the addition of thermodynamic performance monitoring. They conducted an extensive study of available products and features, along with identifying

EfficiencyMap™ Thermodynamic Performance Software

Designed to work with machinery from any OEM, it enables both combined-cycle and conventional thermal power plants to operate more efficiently and profitably within given constraints.

At the heart of EfficiencyMap is GE's GateCycle™ heat balance software, which runs a real time numerical simulation of the plant for data validation and optimization calculations. The data validation process utilizes hundreds of iteration steps to determine the set of data that closes the mass and energy balance equations around the cycle, generating values for every stream property in the entire power generation process. In this manner, measurement errors and estimated values can be identified and corrected, greatly reducing the dependence on high quality, calibrated, installed instrumentation. This is a significant advantage over more simplistic performance algorithms imbedded in plant control systems, which are usually handicapped by instrumentation problems.

The model-based analysis lets the user compare where they are presently operating to where they could be, for a new and clean machine. This shows


Plant Overview

Ambient Conditions
T 27.214 C
P 14.638 psia
WB 25.849 C

Gross Power Summary	
Plant	1128.9 MW 1229.3 MW
Block 1	282.71 MW 308.69 MW
Block 2	278.78 MW 306.30 MW
Block 3	284.21 MW 305.37 MW
Block 4	284.17 MW 309.02 MW

Plant Gross HHV Heat Rate 7866.9 Btu/kWh 7921.2 Btu/kWh Last Update: 02-02-2006 20:05

Time is in "mm/dd/yyyy" format

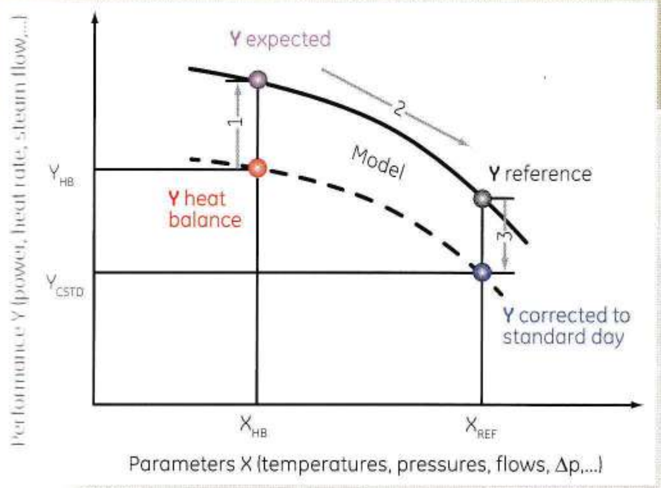
Abbreviations:
T Temperature
P Pressure
RH Relative Humidity

Color Key:
Black Measured
Red Heat Balance
Blue Corrected

their own needs in such a system. A significant factor in their decision was to find a supplier who had the best working knowledge of their plant's equipment and cycle. After independent research and comparison of products, REGCO selected GE's EfficiencyMap™ software as the best fit for their needs.

An Integrated Environment

The EfficiencyMap and System 1 products were developed independent of one another, and became part of GE's offering only after GE's acquisition of Enter Software and Bently Nevada, the respective developers of the two software platforms. While developed independently, the products are highly complementary with one providing insight to the mechanical condition of equipment and the other providing insight into the thermodynamic condition of equipment. REGCO was instrumental in the earliest efforts to integrate the two systems, as the first installation in which EfficiencyMap software was integrated directly with System 1 software, rather than via an intervening product such as a plant data historian application. This direct integration has allowed the EfficiencyMap product to benefit from System 1 capabilities, such as custom rules that can automatically diagnose both mechanical and thermodynamic data, issuing Decision Support advisories and communication plans to best support a proactive maintenance initiative. The result is an integrated environment from which both mechanical and thermodynamic machinery condition can be monitored and optimized.


Performance Y (power, heat rate, steam flow,...)
Y expected
1
2
Model
Y reference
3
Y_{HB}
Y heat balance
Y_{CSTD}
Y corrected to standard day
X_{HB}
X_{REF}
Parameters X (temperatures, pressures, flows, Δp,...)

Like System 1 software's ability to perform detailed asset- and component-level "drill down" diagnostics for mechanical problems, EfficiencyMap software provides the real degradation impact in terms of MW, Heat Rate (or efficiency), or variable cost of generation ($/hr). The model also provides an accurate means to relate current equipment degradation to the reference conditions for long-term trending, independent of actual load, temperature, or other variable conditions, eliminating the need for empirical "correction curves."

A particularly valuable feature is the on-line optimizer where EfficiencyMap software provides the operator with real-time advisories for the best controllable setpoints to meet the committed demand or emission target at minimum cost. For greatest benefit, many customers have chosen to implement this optimizer in closed-loop mode though use of GE's CLOC™ system*. In offline "what-if" mode, the EfficiencyMap plant optimization model supplies the user with accurate prediction of future capacity and cost of generation while accounting for current equipment degradation.

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* See "Closing the Performance Loop" ORBIT Vol 25 #2 2005, pp. 4-16.

similar functionality for thermodynamic diagnostics. Applying model-based performance analysis at the equipment level, it provides capabilities useful for not only maintenance planning, but also for identifying sources of degradation and associated cost or MW losses. Combined, these mechanical and thermodynamic monitoring capabilities allow REGCO to help make sound upgrade and maintenance expenditure decisions as well as the ability to make optimal day-to-day operating decisions.

For example, one of the case histories presented later in this article shows how REGCO engineers were able to use their performance monitoring system to identify a decline in condenser performance, track the actual financial impact of this decline based on current operational requirements, and weigh this against the cost of repairs. This knowledge enabled them to evaluate the urgency of taking action, and to choose the optimal timing to perform the needed maintenance, minimizing the economic impact.

Asset Management at REGCO

REGCO's current maintenance management strategy includes a mix of Predictive Maintenance (PdM) and Preventive Maintenance (PM) on critical machines, with PdM applied rigorously on the balance-of-plant assets. The maintenance management module within REGCO's SAP R/3® software provides the controlled environment for the various condition monitoring technologies to properly integrate with the maintenance process. With scheduled PM events, REGCO's maintenance engineers routinely rely upon the machine condition data from System 1 software to make "go/no-go" decisions on maintenance tasks, allowing them to prioritize resource allocation and minimize plant downtime.

The major long-term initiative currently underway at REGCO is to get the best business advantage from the 2009 PPA extension. Although the plant has only just begun collecting data to work towards negotiating a more challenging agreement, it is clear that the System 1 platform plays a central role in REGCO's ability to commit to higher plant availability and reliability.

Another aspect of the System 1 platform that is important for REGCO is the ability to embed operational knowledge and experience into the Decision Support module as a "learning repository." REGCO has always had a strong business culture of operating as a continuous learning center, striving for continual improvement. This culture can be traced in large part to REGCO's managing director — himself a former performance engineer.

While REGCO has become considerably more self-sufficient in the use of their installed systems, they chose to partner with GE Energy to support and maintain the instrumentation via a supporting services agreement. Also, they consider GE's local Bently Nevada machinery diagnostic engineering staff to be an extension of their own O&M team.

Results

In a gas turbine combined-cycle plant, output is significantly affected by ambient air temperature. In addition, inlet filter fouling and compressor section fouling causes deterioration over a relatively short time frame (weeks or months) compared with other industries. As such, the recent addition of EfficiencyMap software to their system has been particularly beneficial.

Because the plant currently operates with each unit on frequency control (rather than load control), the real-time optimization capabilities of EfficiencyMap can only be partially exploited. However, future system control and asset dispatch practices at REGCO may change this. Even under these constraints, the EfficiencyMap installation paid for itself within the first six months as will be shown in the following case histories. Likewise, the System 1 platform has consistently delivered value during the six years it has been in use at REGCO. In fact, since the system has been installed, REGCO has received a regular stream of inquiries from other power generators and even outside industries, interested in finding out more about the successes achieved through tight integration of REGCO's condition monitoring, performance monitoring, and maintenance management platforms.

Case History #1

Steam Turbine Gland Seal Rub

Unit 30 has a combined HP and LP steam turbine rated at 102 MW and contributes approximately 10 MM USD per year to REGCO revenues. During an October 2003 major overhaul of the unit, all labyrinth seals and bearings were replaced. Figure 1 shows the HP seal discussed in this case history, indicating its location and relative size.

On October 23, 2003, the unit was cold started and high shaft vibration amplitudes at the HP turbine's NDE bearing resulted in a trip as the unit reached its 1000 rpm heat-soak speed. Three unsuccessful starts were attempted before a GE machinery diagnostics engineer was enlisted to review the data captured by the System 1 software. With revenue penalties of approximately 1,600 USD per hour, an understanding of the problem and a course of action to remediate it was urgent.

A preliminary study showed an increasing vibration amplitude trend, even though the machine was at steady speed. This is shown in Figure 2.

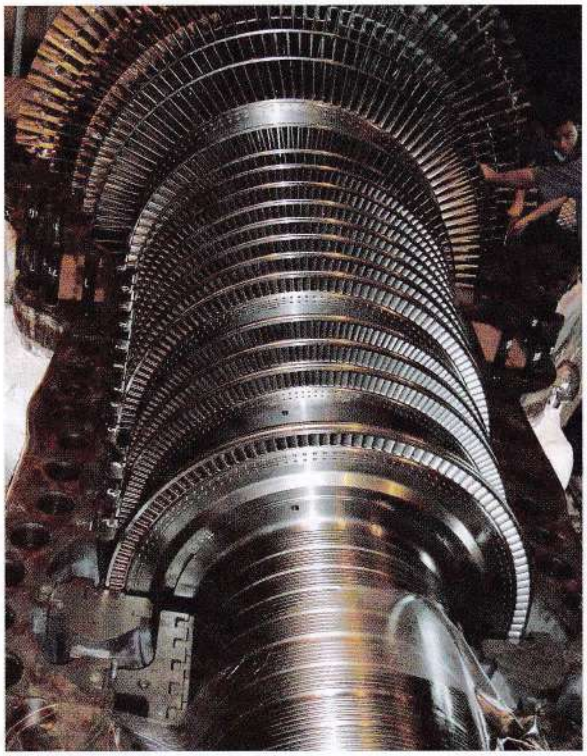


Figure 1 – **The unit 30 Steam Turbine rotor, showing the gland steam seal of the HP turbine stage.**

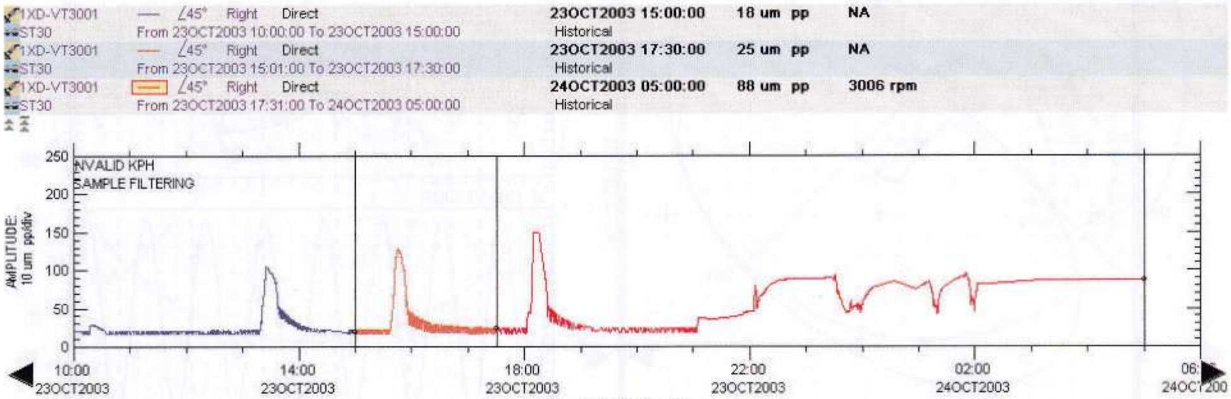


Figure 2 – **Trend plots of shaft vibration amplitudes at #1 bearing (HP turbine NDE) during the three aborted start ups, followed by a successful start on the fourth attempt.**

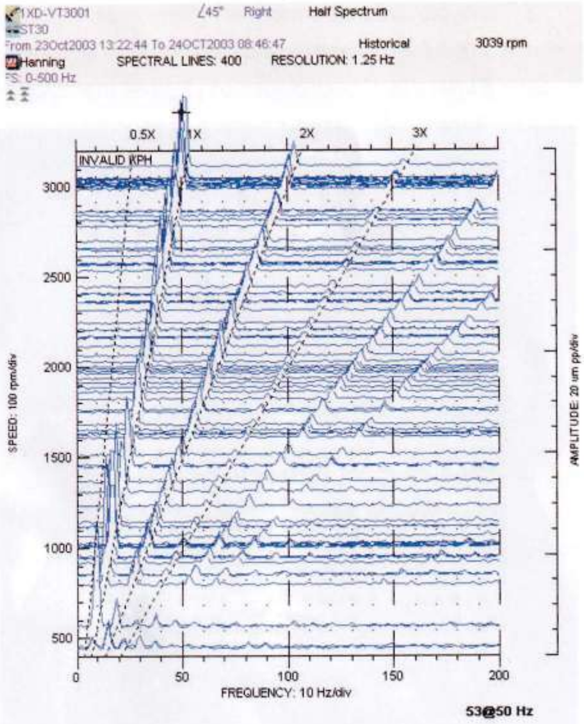


Figure 3 – **Shaft vibration cascade spectrum plot for the #1 bearing "x" probe, indicating vibration frequency is predominantly synchronous (1X). The #1 bearing "y" probe as well as plots from the #2 bearing showed similar features.**

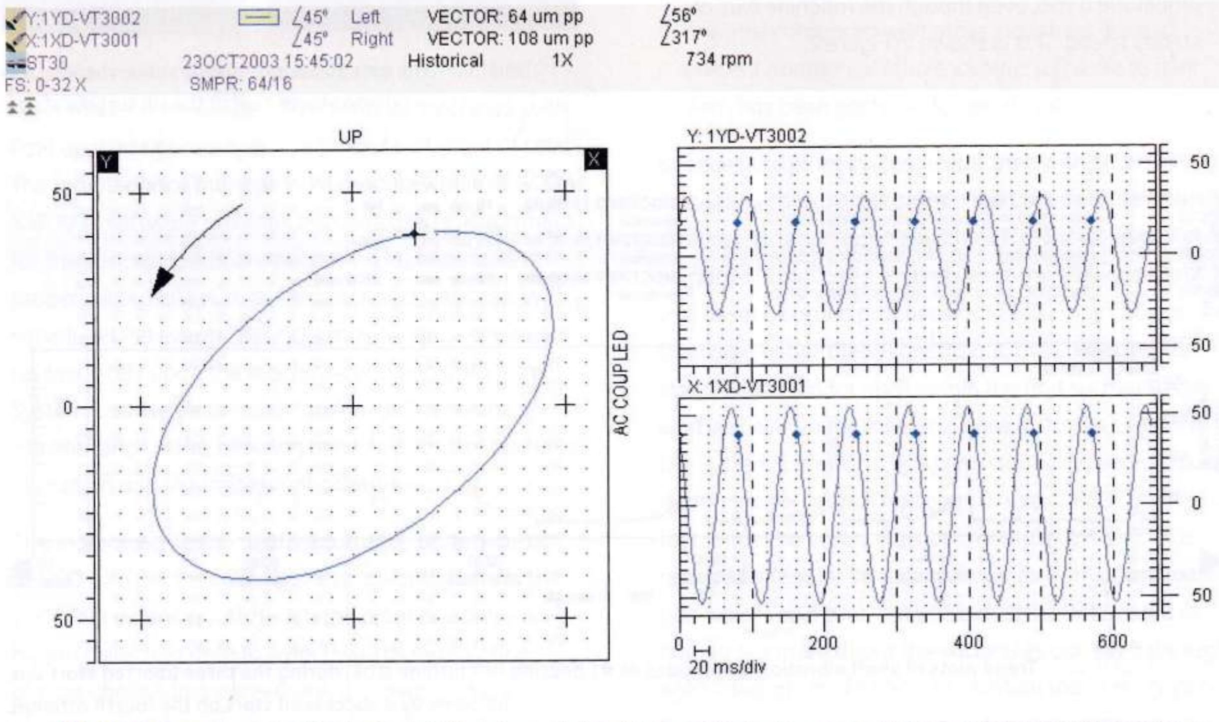


Figure 4 – **Filtered orbit plot from #1 bearing exhibits high amplitude at low speed along with forward precession and a relatively circular shape.**

Analysis of the spectrum cascade (Figure 3) along with unfiltered shaft orbit plots revealed that the vibration was fundamentally synchronous (1X) in nature. Also, because the filtered shaft orbit plots (Figure 4) appeared relatively rounded and exhibited forward precession, misalignment was not considered to be the likely root cause.

An examination of the polar plot data collected during the aborted startup attempts showed that the shaft was tending to deflect in-phase at either end. In other words, it appeared to be bowing. However, consecutive runs were not consistent. Figure 5 illustrates this with each run color-coded, showing how the relative location of the shaft bow changed from one run to the next.

Another interesting observation from the same polar plot was the increasing phase lag during the initial speed increase through the 1100-1200 rpm range. This is consistent with a rotor critical speed being close to the heat soak speed; a subsequent inquiry confirmed this.

Diagnosis of this data suggested behavior consistent with a rub between the rotor and the tight HP gland seals when the shaft speed increased towards the rotor critical speed. It was further reasoned that holding the machine for heat soak within the critical speed range was exacerbating the rub.

The standard recommendation in such situations is to run the unit on turning gear for four to six hours

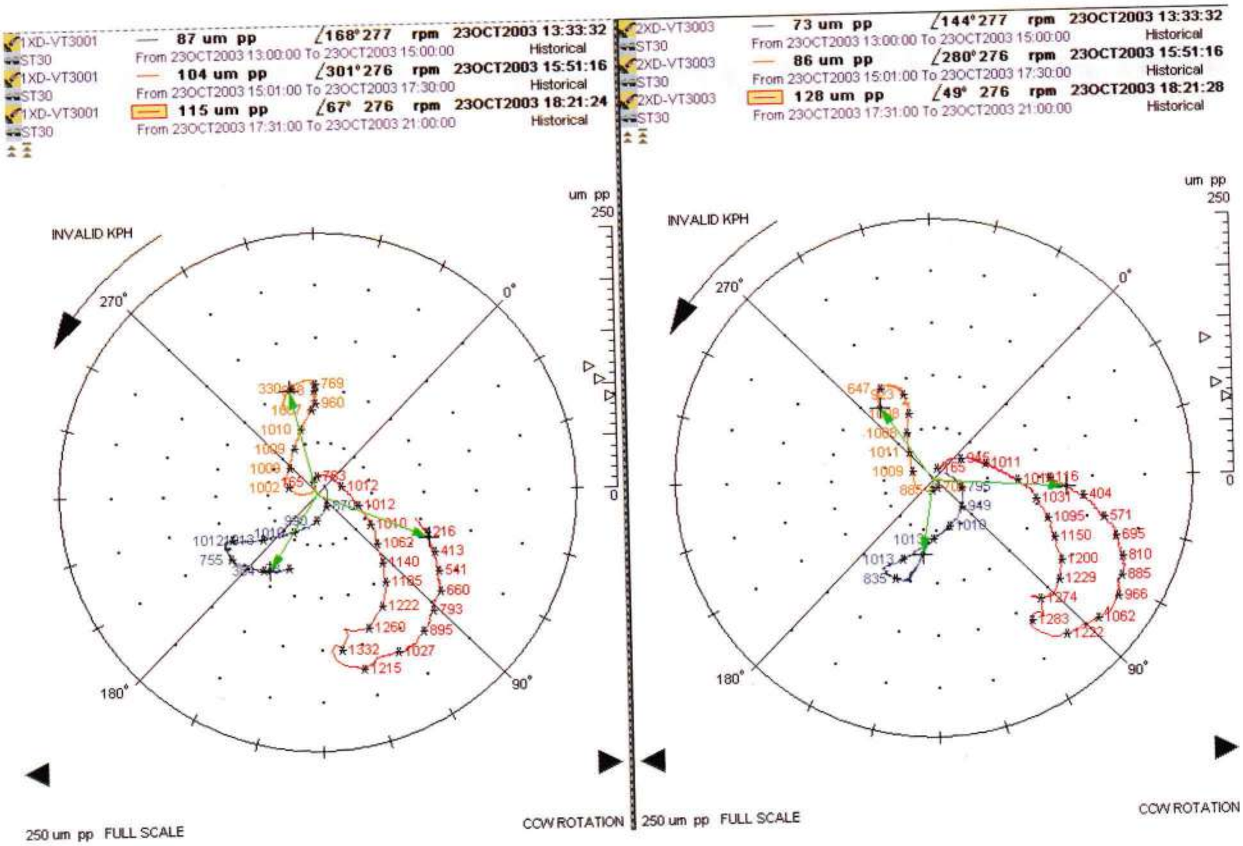


Figure 5 – **Polar plots of #1 (left) and #2 (right) bearing vibration showing three unsuccessful start-up attempts. Note the shaft deflections at each end of the rotor are in-phase with each other, as noted by comparing the phase of each plot to one another for each run and speed. Notice also that the apparent "heavy spot" (the location at which a 90-degree phase shift occurs) differs for each run, as shown by the green vectors.**

to straighten the shaft before attempting the next startup. This type of rub on cold startup is not uncommon and is often tolerated in the expectation that the new labyrinth seals will wear in, provided it doesn't lead to excessive gland steam leakage. However, due to the large financial impact of several additional hours of lost production and corresponding penalties, and because the heat soak was relatively close to the turbine critical speed, a modified startup procedure was proposed. The machine would be closely monitored during a heat soak at a lower speed (around 500 rpm) that did not correspond to a rotor resonance. This would allow the machine to ramp directly through the critical speed range without dwelling long enough for a light rub to generate a thermal bow.

This use of System 1 software, coupled with the machinery diagnostic expertise of GE's local team, enabled the root cause to be quickly identified and an effective solution implemented immediately. The solution was so effective, in fact, that REGCO later implemented the modified startup procedure as part of their standard operating practices for the unit. The immediate benefits of eliminating the additional straightening time on turning gear (four to six hours) is worth up to 6000 USD per startup. With an average of 15 starts/stops per year, this approaches 100K USD annually. Savings also accrue from the incremental efficiency gains made by maintaining tighter seal clearances over a longer time period.

[Savings: In excess of 100,000 USD]

Case History #2

Condenser Air Leakage

During August 2005, operators identified increased heat rate on Unit 20's steam turbine. While this appeared to correlate with increased condensate temperature, the measured condenser pressure reported by the DCS still appeared within limits (black trend in Figures 6 and 7). The turbine is designed to exhaust into a considerable vacuum to extract maximum energy from the working steam, so condenser pressure is a critical parameter for plant performance.

Although the PPA agreement generally allows for pass-through of fuel costs, this is based upon the contracted heat rate value, which is audited annually. Any increase in heat rate will therefore result in a significant, and unrecoverable, excess fuel cost penalty.

The EfficiencyMap system, which had been commissioned in early 2005, immediately confirmed a significant degradation of the "heat balance" calculated condenser pressure when compared with the "expected" pressure. Importantly, the "heat balance" validated pressure measurement (red trend in Figures 6 and 7) was significantly different than the measurement seen by plant operators, immediately suggesting a field sensor problem.

The "corrected" pressure (blue trend in Figures 6 and 7), which normally trends steadily regardless of plant operating state, revealed a pressure increase and significant fluctuation in value, indicating the nature of the problem was not steady state. EfficiencyMap software quantified the impact of condenser-related heat rate degradation due to this event as approximately 3,500 USD per day in excess fuel costs.

Air leakage was suspected and station chemists confirmed high levels of dissolved oxygen in the condensate, confirming the diagnosis. A manual inspection with an ultrasonic leak detection device quickly found the leakage point: a cracked weld in the steam warming line. Because this line normally operated at relatively low pressure during startup, only a minor steam leakage would have been seen during warm-through on startup.

A temporary repair was carried out, using silicon sealant to temporarily seal the air ingress point until the next opportunity for weld repairs (Figure 8).

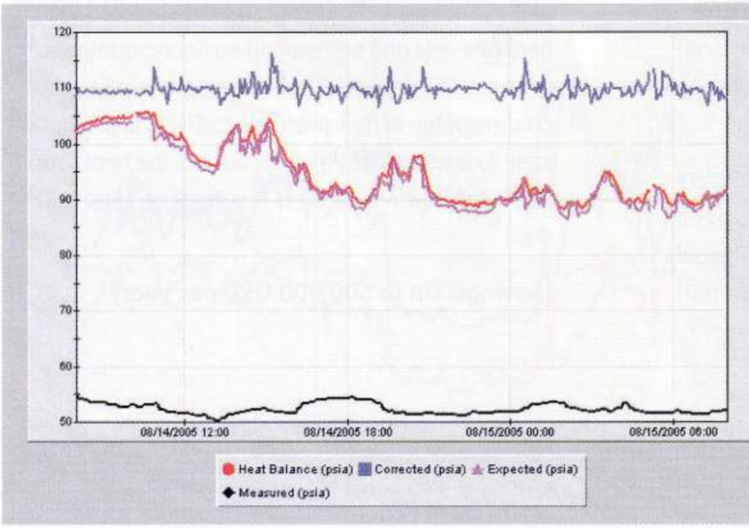


Figure 6 –

Trend plots of condenser backpressure prior to heat rate increase.

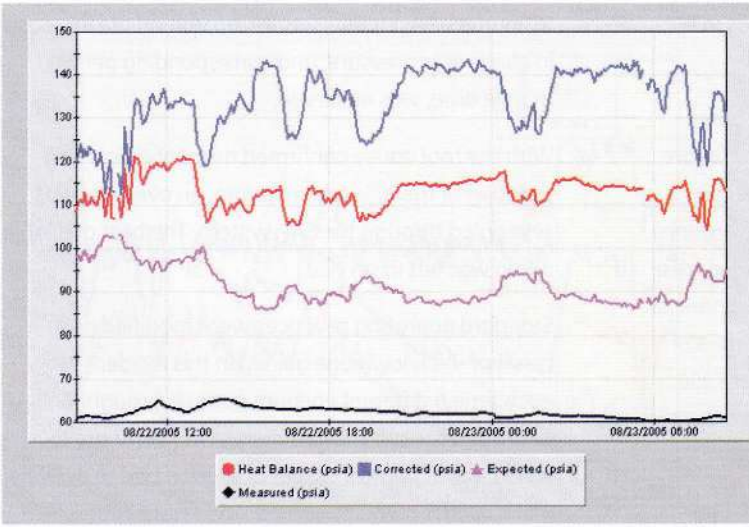


Figure 7 –

Trend plots of condenser backpressure after operators observed an increase in unit heat rate. Note the deviation from "expected" (pink) and "heat balance" (red) pressure values.

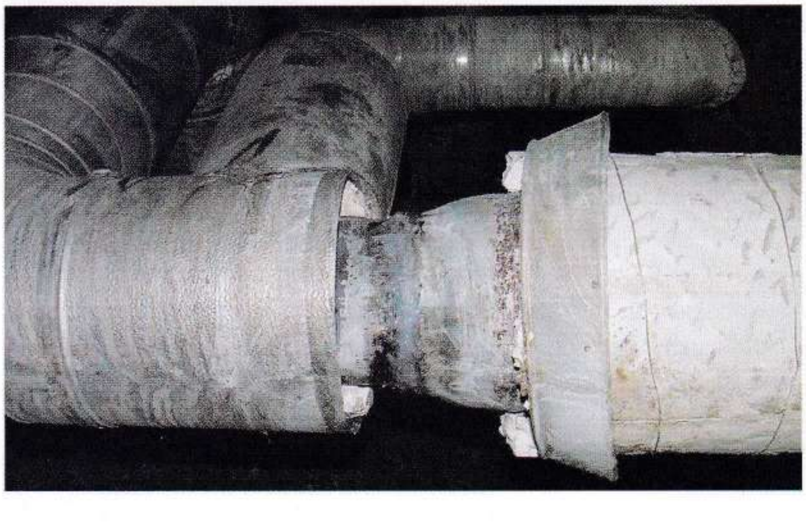


Figure 8 –

The warming line with lagging removed showing temporary repair using sealant around the cracked weld.

Following running repairs, condenser pressure trends returned to values similar to those prior to the leak (refer to Figure 6), with no evidence of residual degradation to the condenser.

The advantage of the model-based data validation routine incorporated in EfficiencyMap software can clearly be seen in this case study. Analysis using only raw DCS data could not have revealed the severity of the problem. Neither could it have revealed the heat rate loss and corresponding financial impact. In contrast, the online performance data provided by EfficiencyMap software enabled REGCO to promptly identify and correct the root cause of the heat rate degradation, saving excess fuel costs of 3,500 USD/day.

[Savings: Up to 500,000 USD per year]

Case History #3

Managing Vacuum Pump Degradation

The REGCO condensers are each equipped with 3 vacuum pumps — one duty pump and two backup pumps. In August 2005, vacuum pump "C" was in service.

On August 19th, with the unit at steady-state operation, operators reported that EfficiencyMap software was indicating an increasing corrected condenser pressure (Figure 9). It was also indicating a divergence of the "heat balance" and "expected" condenser pressure values. The software also quantified the financial impact of this performance degradation, in terms of excess fuel consumption: it had increased from 260 USD/day on August 19th to 2,600 USD/day two days later.

In order to recover heat rate and restore back pressure, a second vacuum pump was put into service on August 21st. While this was successful in restoring the condenser pressure, it raised the suspicion of a possible mechanical problem with the initial vacuum pump. Consequently, the operators carried out a series of operational tests to confirm. Each of the vacuum pumps was operated in turn while watching the plant performance trends (Figure 10). The EfficiencyMap software clearly showed that when the "C" pump was put into service, an immediate increase in condenser pressure, and corresponding performance drop, was observed.

With the root cause confirmed as mechanical degradation of the "C" vacuum pump, an overhaul was scheduled through the SAP system. The best available pump was left in service

Standard operating practices were modified as a result of the knowledge gained in this incident. Now, each time a different vacuum pump is brought online, operators consult their EfficiencyMap software to validate that pump's proper operation and to actively minimize the cumulative heat rate losses that would otherwise be incurred.

This use of EfficiencyMap software to prioritize the selection of vacuum pumps based on performance reduced excess fuel cost from 2,600 USD per day to 1,770 USD per day.

[Savings: Up to 130,000 USD per year]

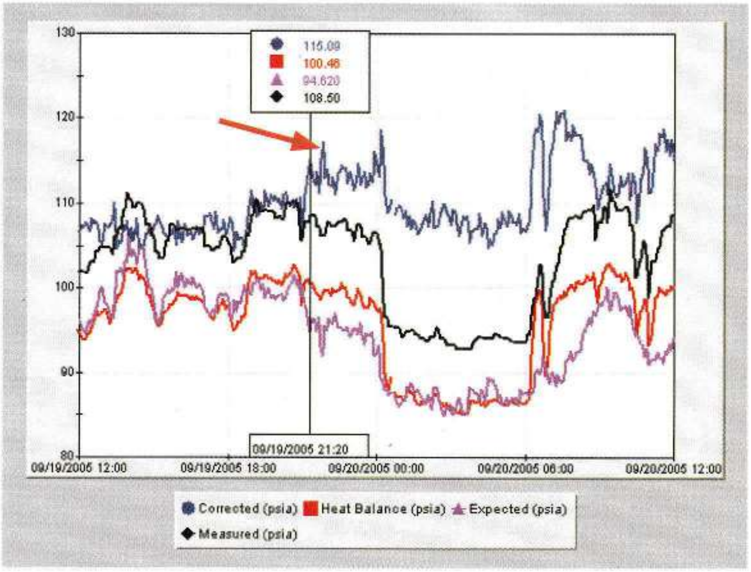


Figure 9 –
EfficiencyMap software trend plots showing increase in the "corrected" condenser pressure along with divergence of "heat balance" (red) and "expected" (pink) pressure values when the "C" vacuum pump is in service.

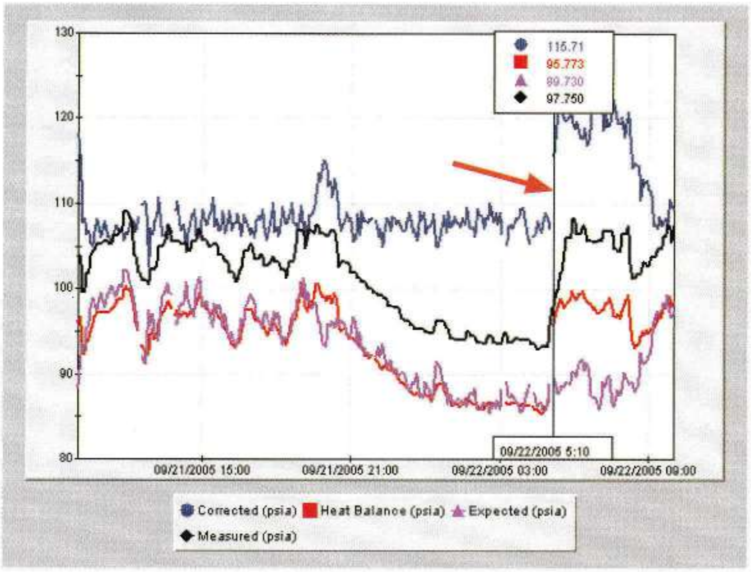
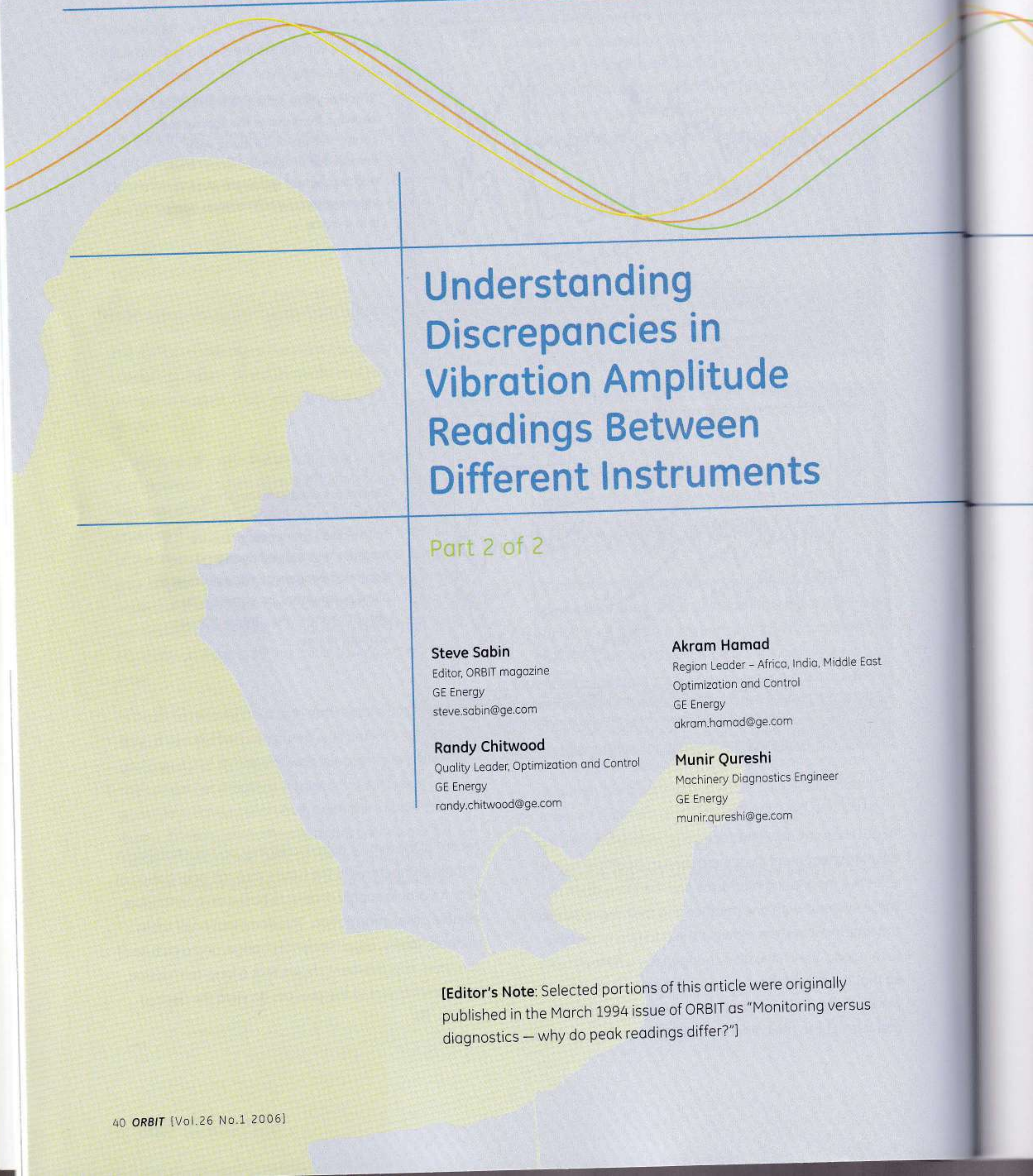


Figure 10 –
Operators used EfficiencyMap software to confirm that the "corrected" condenser pressure increase was caused by the degraded vacuum pump, not other plant parameters, as noted by the abrupt change when pump "C" was brought online.

Summary

REGCO has strongly embraced a proactive approach to asset management and operations through the use of effective monitoring platforms and the integration of these systems with one another and their maintenance management system. However, in addition to capable technology, they have also changed the way they work so that these tools have become a part of their normal work processes. The use of these systems plays a pivotal role in both the company's ability to sustain its track record of extremely high availability, and in its ability to remain competitive in the future through negotiation of very favorable supply contracts based on quantifiable, reliable asset information. This combination of tools, methodologies, organizational change, and a culture of continual improvement shows that a long-term vision and commitment to the process do yield the desired results.



Understanding Discrepancies in Vibration Amplitude Readings Between Different Instruments

Part 2 of 2

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[**Editor's Note**: Selected portions of this article were originally published in the March 1994 issue of ORBIT as "Monitoring versus diagnostics — why do peak readings differ?"]

Introduction

In part 1 of this 2-part article, we began an in-depth look at the answer to a question that arises numerous times each year from our customers: "I took a vibration reading with a portable diagnostic instrument, but it does not agree with what I am seeing on my Bently Nevada™ monitor. Why?"

Customers often assume that there must be a problem with the monitor, the diagnostic instrument, or both. However, as explained in part 1 and as repeated here, this is rarely the case. Instead, there are some very straightforward reasons why there are often discrepancies in vibration readings between two instruments – particularly peak-to-peak amplitude readings.

In our previous article (ORBIT Volume 25, Number 2, 2005), we defined four stages of a signal as it travels through a vibration measuring instrument. For convenience, those stages and the corresponding diagram are repeated below as Figure 1.

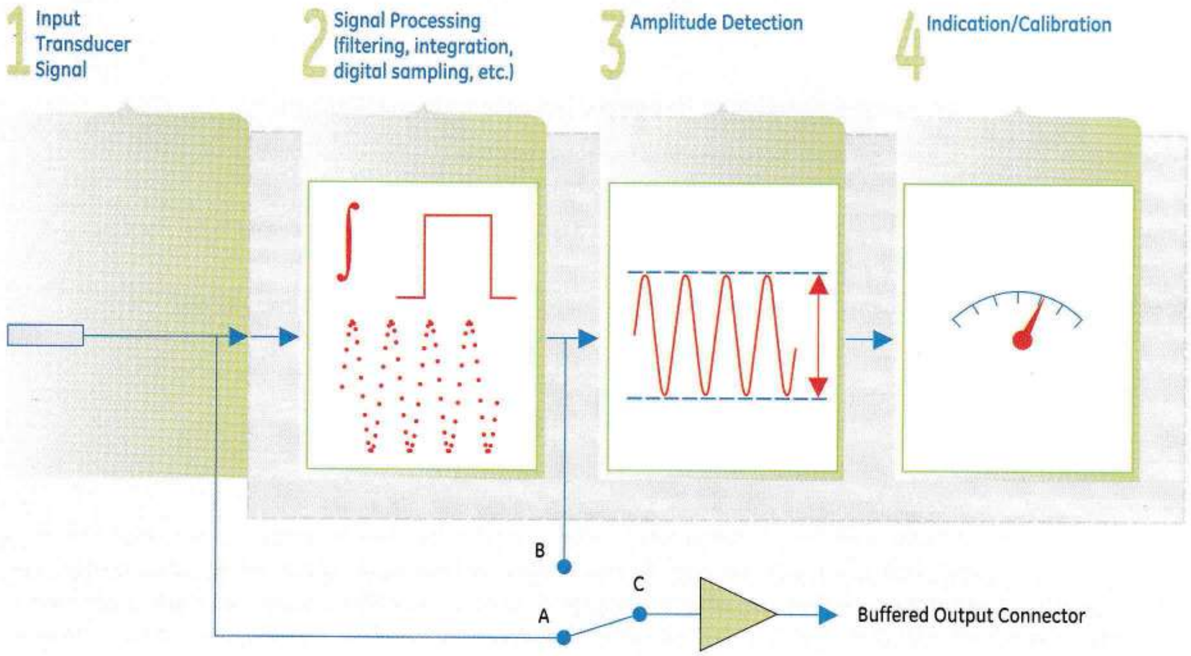

1 Input Transducer Signal
2 Signal Processing (filtering, integration, digital sampling, etc.)
3 Amplitude Detection
4 Indication/Calibration
B
C
A
Buffered Output Connector

Figure 1 – **By considering the four stages of a signal as it travels through an instrument, it is easier to understand and isolate discrepancies in readings between two devices.**

In part 1, we examined stages 1 and 2. Here, we continue by investigating stages 3 and 4. Stage 3 involves the circuits/algorithms used to actually perform the amplitude detection function in a variety of modern vibration instrumentation, and we will explain the differences between these various algorithms. Stage 3 is notable in that it accounts for more discrepancies in readings than any other single factor and is often the aspect least understood by users. As such, we devote a majority of part 2 to educating the reader on this important topic.

We then conclude with a brief discussion of stage 4: calibration/indication issues. Ironically, when customers contact us to report discrepancies in readings between GE's Bently Nevada™ instruments and those of other manufacturers, they often assume the discrepancies are due to calibration problems or indication malfunctions. However, in our experience, these are actually the least common reasons for discrepancies. Nevertheless, they can affect older analog systems as well as any system that has not been properly configured, and are included in this discussion for completeness.

Measurement Conventions

In part 1, we defined the measurement conventions used for describing a vibration signal's amplitude in all Bently Nevada™ instrumentation. For ease of reference, we present them once again in Table 1 below and Figure 2 on the next page.

Part 1 also discussed the discrepancies that can occur due to differences in conventions for whether peak readings are defined as pp/2 (as in all Bently Nevada instruments) or as the larger of the waveform's positive- or negative-going peak. When a waveform is asymmetrical, as in Figure 2B, these differences in conventions will indeed result in discrepancies.

Another facet that we briefly addressed was the convention for determining the RMS amplitude of a signal. There are two primary methods for measuring the RMS amplitude of a generalized waveform. The first is by way of analog circuitry that essentially solves the integral given in Table 1, providing an output proportional to the RMS value of the waveform. This is known as a "true RMS" circuit. However, such a circuit has no way of

Table 1 –

WAVEFORM AMPLITUDE CONVENTIONS USED IN BENTLY NEVADA INSTRUMENTATION

Peak-to-Peak (pp)	The difference between the maximum positive-going and negative-going peaks in a periodic waveform during one complete cycle.
Zero-to-Peak (pk)	The pp value of a vibration signal divided by two (pp/2). Also referred to as "true peak."
Root Mean Square (RMS)	A measurement of the effective energy content in a signal. Mathematically, the RMS value of a waveform f(t) is defined as $A_{RMS} = \sqrt{\frac{1}{T} \int_{t_0}^{t_0+T} f(t)^2 \, dt}$ where T is the period (one complete cycle) of the waveform*.

* To accommodate all expected periods in generalized waveform inputs to an instrument, T is typically chosen for computation purposes to coincide with the lowest frequency measurable by the instrument. Thus, an instrument with a bandwidth down to 0.5 Hz would use $T = 2$ seconds.

detecting the period (T) of a single waveform cycle. As such, T becomes the length of the measurement period, rather than a single waveform cycle. T is typically chosen to accommodate the lowest frequency of interest in the instrument's bandwidth. For example, if the instrument is to handle waveforms with frequency content as low as 0.5 Hz, it will take 2 seconds to compute an accurate RMS value, since the period of a 0.5 Hz wave is 2 seconds. There are also digital emulations of analog RMS circuits, and this is the approach taken in newer Bently Nevada instrumentation.

The other method of RMS detection is digital, but it is not simply a digital emulation of an analog circuit. Instead, it approximates the RMS value of a waveform by quadratically combining the amplitudes of all spectrum lines and then taking the square root. We will examine this digital RMS algorithm in considerably more detail later in this article. For the moment, we will merely point out that it is the basis of digital RMS calculations in many portable data collectors and can vary considerably from the value given by analog RMS circuits, depending on how the user has configured their spectrum sample.

(continued on page 45)

Key Point

The relationship between peak and RMS is commonly denoted as the Crest Factor (CF) where pk = CF x RMS. **The CF is not a constant** – it is completely dependent upon the shape of the waveform (i.e., frequency and phase content) and will differ between waveform shapes. For example, the CF for a square wave is 1, the CF for a pure sinusoid is 1.414 (i.e., $\sqrt{2}$), and the CF of the waveform in Figure 2B is 2.06. **Do not make the mistake of using a single CF (such as 1.414) to apply to any generalized waveform.** Instead, accurate conversion between RMS and pk or pp readings must always use the relationships of Table 1. Many discrepancies in readings can be traced to the erroneous use of a "scaling factor" (such as CF) when converting between pk and RMS. CF must be interpreted in the same way a practitioner would interpret the spectrum of a waveform: it is **unique** to that waveform.

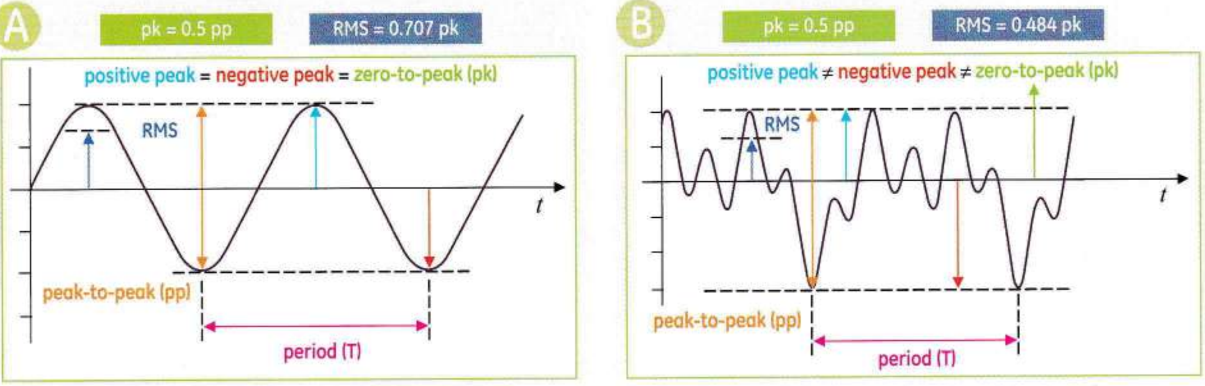


Figure 2 – **Peak-to-peak (pp), zero-to-peak (pk), and RMS are the most commonly used conventions for expressing the amplitude of vibration waveforms. The conversion between RMS and pk is only equal to 0.707 for a pure sine wave (A). For a more complex signal (B), the equation of Table 1 must be used to compute the RMS value. The conversion between pp and pk can differ between manufacturers and becomes apparent if the waveform is asymmetrical (B). When using the Bently Nevada instrumentation convention of pk = pp/2, the pk value may not be equal to either the positive or negative peaks on an asymmetrical waveform.**

Root Mean Square (RMS)

The origins of RMS as a way of describing a signal's amplitude lie in electrical engineering, where a method was needed to compare an ac signal's ability to deliver power with that of a dc signal. Thus, an ac signal with an RMS value of 1 volt will deliver the same power to a resistive load as will a 1 volt dc battery. RMS is so widely used in electrical engineering that ac signals involved in power utilization are almost always denoted in terms of their RMS values. For example, the 110/220 Vac conventions used for residential wiring worldwide are RMS voltages. This corresponds to 156 and 311 Vac pk respectively. In fact, many voltmeters and multi-meters are designed to measure signal amplitude in terms of RMS values, while also providing a peak amplitude setting. When using such meters in conjunction with vibration measurements, it is important to understand if the meter provides true peak and RMS measurements, or if it simply converts between pk and RMS using the factor 1.414. While such conversions are suitable for applications involving pure sinusoids (such as residential wiring with minimal "noise"), they do not hold true for generalized waveforms, or even for conventional 60 or 50 Hz power where appreciable noise is present.

A very common mistake made by practitioners when calibrating or verifying the operation of vibration instruments is to measure the signal amplitude using a voltmeter or other instrument that returns an RMS value, and then erroneously convert to a "peak" amplitude by multiplying this RMS value by 1.414. Unless the signal of interest is a pure sinusoid (such as the vibration signal filtered to only its 1X component), the relationship pk = RMS x 1.414 does **not** hold true.

A simple test to determine whether your instrument uses a "scaled RMS" or a "true peak" measurement is to input a square wave using a signal generator. This waveform is chosen because it is comprised of complex frequency components and is also the only waveform that has identical pk and RMS values. Adjust the amplitude on the signal generator to 2 volts pp (1 volt pk) **as observed on an oscilloscope**. Also, be sure to adjust the frequency of the waveform so that it is well within the bandwidth of your instrument (we recommend using a square wave frequency at least 25 times less than the frequency response of your instrument, due to the importance of the higher harmonics in representing a square wave faithfully). Make a note of your instrument's scale factor and observe the reading. For example, if your instrument has a scale factor of 100 mV/in/sec pk and you input the square wave above, you will observe approximately the following values:

"True Peak" circuit: 1 volt pk ÷ 100 mV/in/sec = 10 in/sec

"Scaled RMS" circuit: (1 volt rms ÷ 100 mV/in/sec) x 1.414 scaling factor = 14.14 in/sec

Do not use a pure sinusoid to conduct such tests, as this waveform will always produce the same results whether your instrument uses a "true peak" circuit or a "derived peak" circuit, as shown below:

"True Peak" circuit: 1 volt pk ÷ 100 mV/in/sec = 10 in/sec

"Scaled RMS" circuit: (0.707 volt rms ÷ 100 mV/in/sec) x 1.414 scaling factor = 10 in/sec

(continued from page 43)

Dissimilar Amplitude Detection Algorithms

We divide our discussion here into two parts: amplitude detection used in GE's Bently Nevada instrumentation, and amplitude detection used in other instrumentation.

Bently Nevada Peak Detection

All true peak-to-peak (pp) detectors have fundamental performance factors that affect their ability to respond to various input waveforms. These performance factors are the same whether the circuit is analog or digital in nature and regardless of whether the circuit displays pk or pp readings. During the nearly fifty years that we have been producing Bently Nevada instruments, two basic types of pp detectors have been employed in these products to measure vibration. One type of pp detector is reserved for monitor systems such as 3500 and 3300, while the other type is used in diagnostic instruments such as the ADRE® System. These different detectors are used because of the different uses of the instruments (see sidebar at right).

There is no difference in the measurement of peak-to-peak between a Bently Nevada monitor and diagnostic instrument (within the device's frequency response) when both are measuring "clean" waveforms. The chief differences are exhibited when processing waveforms with transient noise.

1. Monitor pp Detection

First, we consider the circuit used in Bently Nevada monitors. These systems have evolved to provide extremely reliable machine monitoring. This relies, in part, on the monitor's ability to perform the pp detection function while minimizing susceptibility to noise. Originally, this was achieved by using analog circuits consisting of diodes, resistors, and capacitors. The resistor-capacitor (RC) components gave such circuits distinctive charge/discharge time constants. Today's systems use digital technology; however, they have been intentionally designed to emulate the response of these older analog pp circuits, providing

Monitoring Versus Diagnostics

Depending on the instrument's primary purpose, different philosophies are employed in GE's Bently Nevada™ product line regarding signal processing. For purposes of this article, we can divide vibration-measuring instruments into two broad categories: diagnostic instruments and continuous monitoring instruments*.

For diagnostic instruments, the goal is to provide a measurement similar to what would be observed on an oscilloscope, tracking all information in a transducer signal regardless of origin. The objective is to facilitate detailed diagnostics, allowing the engineer to ascertain everything present in the signal, whether it is actual mechanical vibration, electromagnetic interference, scratches on the shaft, or anything else. Diagnostic instruments generally take a limited duration "snapshot" of the signal. The signal during that particular window of time is processed through an analog circuit or, more commonly with modern instruments, a digital algorithm that provides the signal attribute of interest, such as frequency components or waveform amplitude.

In contrast, a continuous monitoring system has a continuous stream of input data and is expected to provide a continuous output, generally an indication of the overall vibration amplitude used for comparison against alarm setpoints to help protect the machine. For continuous monitoring instruments, the goal is to faithfully represent the actual mechanical vibration present, but to incorporate signal processing techniques that improve the system's immunity to spurious signals — such as transient noise — that would result in false alarms or trips.

To reflect these differences in applications, distinctly different peak-to-peak detection circuits are employed.

* Our Snapshot™ family of portable data collectors actually uses a slightly different algorithm for peak detection than either our monitors or diagnostic instruments. However, it generally emulates the response of our monitoring systems, allowing pk and pp readings from our data collectors to agree closely with that of our monitoring systems for most waveforms.

consistency between various historic and current monitoring systems, and ensuring that a retrofit from an older system to a newer system will produce the same readings.

The response of this type of peak-to-peak detector is shown in Figure 3. This type of detector continually processes the incoming signal. Its output is constantly adjusted based on the instantaneous value of the incoming signal and the circuit's memory of past peaks. When the input signal exceeds the circuit's memory of past peaks, the output increases. We describe this as "charging." When the input signal is less than the current memory of the past peaks, the output decreases. We call this "discharging."

These charge and discharge cycles work as follows:

– *Monitor Charge Cycle*

Analog pp detector circuits used in older Bently Nevada monitors used a peak capacitor. The rate at which this capacitor could be charged was limited, based on the circuit design, and the detector circuit would respond to a new peak at a rate of approximately 5% of the monitor's full scale value per millisecond. For example, a monitor with a 10 mil full scale would see a maximum rate of change in its pp detector of approximately 0.5 mils per millisecond. This controlled charge rate has the benefit of reducing the pp detector's response to transient and high frequency noise. Because of the design's success, we haven't changed this characteristic of our pp detection circuits over the years, even though it is technically feasible. Today, of course, the design is realized digitally, rather than with analog components, but the fundamental response of today's digital monitors was intentionally modeled to replicate these older analog circuits.

A result of this limited charging rate is that frequencies with periods of less than 1 millisecond require multiple cycles to "charge" the detector to the input pp value. For example, the pp detector would require approximately 20 cycles to charge to within 1% of its final value if the input were a 1 kHz sine wave.

CUSTOMERS OFTEN ASSUME THE DISCREPANCIES ARE DUE TO CALIBRATION PROBLEMS OR INDICATION MALFUNCTIONS. HOWEVER, IN OUR EXPERIENCE, THESE ARE ACTUALLY THE LEAST COMMON REASONS FOR DISCREPANCIES.

– Monitor Discharge Cycle

If the input signal goes to zero, the peak value will discharge to zero after a certain period of time. The time it takes the circuit to discharge to within 37% of its final value is described as the discharge time constant. Monitoring circuits use two different discharge time constants. The first discharge time constant is the most common. It is used on all monitors optioned for use with seismic transducers and on radial vibration monitors with a low-pass frequency response of 240 cpm. This time constant is approximately 1 second. A longer time constant of 4 seconds is used only on radial vibration monitors with a low-pass frequency response of 60 cpm for very low speed machines. This time constant allows the pp detector to "remember" past peaks for a longer time period.

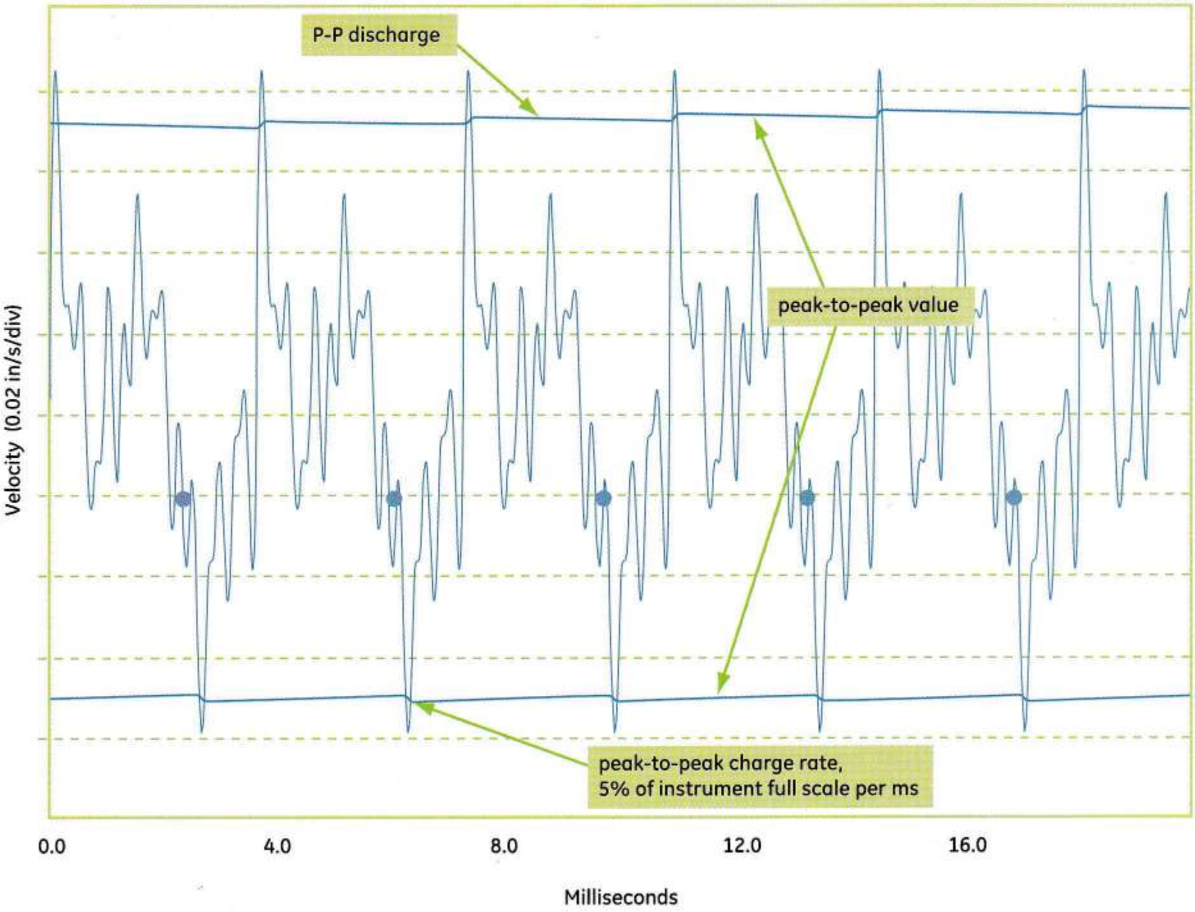


Figure 3 – **The response of the peak-to-peak detection circuit as used in all Bently Nevada monitors (with exception of selected eccentricity and low-frequency monitors). Note the circuit's slow response to the highest amplitude spikes in the input waveform, indicative of transient noise.**

2. Diagnostic pp Detection

The pp detectors used in Bently Nevada diagnostic instruments are designed to calculate peak-to-peak with results equal to what would be seen on an oscilloscope. The goal is to track all information in a transducer signal, regardless of its origin. This type of detector's performance has continually improved over time based on available technology, providing faster and more accurate results. For example, the newly introduced ADRE system (see page 60 in ORBIT Volume 25 Number 2, 2005) features the most sophisticated pp detection circuit we have ever been able to offer.

Bently Nevada diagnostic instruments sample the input for a specific duration or for a set number of shaft rotations. They take a "snapshot" of the signal during this time period, in contrast to a monitor which is constantly providing a value proportional to the current input based on the past inputs. Thus, the diagnostic instrument works very differently during its "charge" and "discharge" cycles, and its response is shown in Figure 4.

These charge and discharge cycles work as follows:

– *Diagnostic Charge Cycle*

During its charge cycle, the diagnostic instrument's pp detector charges much faster than the monitor's

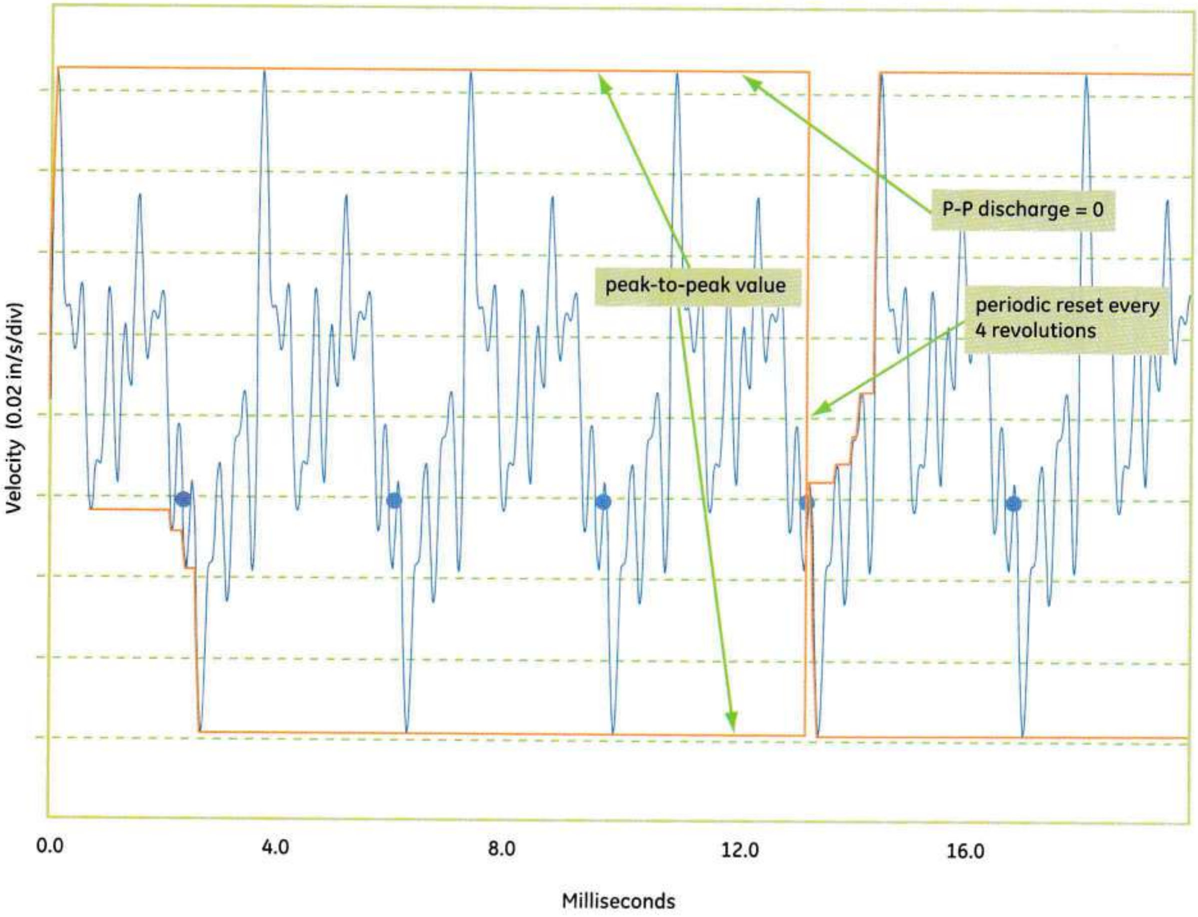
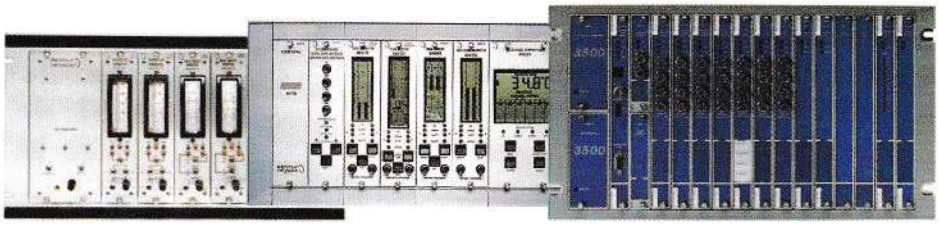


Figure 4 – Typical response for the "sample and hold" type of peak-to-peak detection circuits used in Bently Nevada diagnostic instruments. Note the circuit's response to the highest amplitude spikes in the input waveform.

RMS Detection in Bently Nevada Instruments

Because RMS is inherently an "averaging" operation that conveys the effective energy within a signal rather than information about its peaks, large-amplitude short-duration "spikes" in the waveform do not have the same effect of markedly or instantaneously changing the RMS value as they would a pp value. For this reason, it is not necessary to employ intentional differences in the RMS detection circuitry between monitoring systems, diagnostic systems, and portable data collectors to protect against spurious or transient "spikes" that could result in false alarms or trips. All three use the same algorithm. Although the details of that algorithm are not discussed here, the digital implementation of a true RMS circuit in our current instrumentation is designed to very closely emulate the analog implementation of older monitors. This allows users to upgrade from older monitoring systems to newer systems without concern that there will be marked differences in readings.



The digital algorithms used to compute pk, pp, and RMS in our newer Bently Nevada monitoring systems such as 3500 have been carefully designed to closely emulate the response given in older analog systems such as 7200 and 3300.

detector. In fact, while a monitor's circuit is intentionally designed to have a finite charge rate that helps reject spurious signal content, the goal of a diagnostic instrument is to have an infinitely fast charge rate, allowing it to capture any part of a signal, no matter how fast it is changing. Typically, our diagnostic instruments have a pp detector that charges at a rate 20 times faster than a monitor's pp detection circuit. This makes the diagnostic instrument very responsive to most signals.

– *Diagnostic Discharge Cycle*

During the discharge cycle, diagnostic instruments completely discharge their pp detectors at a set interval or based on a Keyphasor® pulse. The pp value from such a circuit discharges instantly, prior to each new "snapshot" of the input signal.

By comparing Figures 3 and 4, the differences between the pp detection circuit of a monitor (such as 3500) and of a diagnostic instrument (such as ADRE) are readily apparent.

As a final note, recall that the convention used for peak detection in all Bently Nevada instruments is simply the pp value divided by two. Thus, even those monitors that do not provide a pp display option (such as from velocity or acceleration transducers) use the same fundamental peak-to-peak detection circuitry as described above. The peak reading is simply returned as one-half the pp value.

Next, we turn to the question of amplitude detection algorithms used in instruments made by other manufacturers.

Peak Detection in Other Instruments

Earlier, we explained that a true RMS reading must emulate the integral shown in Table 1 if it is to be valid for all waveform types. Also, even if the RMS detection itself is quite accurate, it is not appropriate to simply multiply the RMS value by 1.414 to obtain a true peak value, as this relationship only holds true for a pure sine wave.

Nevertheless, early portable data collection instruments often provided a peak reading that was simply the RMS value x 1.414. Later, more options for waveform amplitude determination were added, but by then, many analysts had become accustomed to this so-called "derived peak" reading and had large databases of historical trends that they did not want to abandon. Thus, the measurement was retained and is present in many data collectors and other instruments under various names. Our purpose here is not to argue for or against the use of this measurement as a trending tool. It is merely to point out that it will bear little or no resemblance to the true peak value of a waveform as observed in a timebase display, on an oscilloscope, or from a Bently Nevada monitor.

Recognizing this, many manufacturers began providing multiple amplitude detection options. For example, the CSI® 2120 and 2120-2 machinery analyzers provide options summarized in Table 2.

Table 3 provides a similar summary, showing nomenclature used by selected instruments in Rockwell Automation's Entek® and Entek IRD® product lines.

Table 2 –

OVERALL WAVEFORM AMPLITUDE DETECTION OPTIONS FOR CSI® 2120 MACHINERY ANALYZERS

Nomenclature	Description	Comparison to Bently Nevada Instrumentation
Digital Overall	The RMS value as calculated by quadratically adding spectral lines, encompassing only the frequency span selected for the spectrum.	Will not agree with pk or pp readings from a Bently Nevada monitor, even if a scaling factor of 1.414 or 2.828 is used. May not generally agree with RMS readings from a Bently Nevada monitor unless bandwidth of both instruments is set equally.
Analog Overall	The RMS value as measured by an analog RMS-to-DC circuit, encompassing the full bandwidth of the instrument.	Will not agree with pk or pp readings from a Bently Nevada monitor, even if scaling factor of 1.414 or 2.828 is used. May agree reasonably closely with RMS readings from a Bently Nevada monitor, depending on bandwidth settings.
True Peak Overall	The maximum positive-going or negative-going peak within the time waveform for the specified sample duration.	May not agree with the pk reading from a Bently Nevada monitor, as this type of algorithm more closely resembles those used in Bently Nevada diagnostic instruments. Also, differs from the Bently Nevada convention of pk = pp/2 which will create discrepancies if the waveform is asymmetrical.
Average Peak Overall	The average of the "true peak overall" calculated by the data collector for a specified number of sample blocks.	May agree more closely with the pk reading from a Bently Nevada monitor, since the algorithm is less responsive to "spikes" in the waveform through its averaging operation. However, the algorithm does not emulate the charge/discharge algorithms used in Bently Nevada monitors (figure 3) and discrepancies may still exist.

Sources:

Reference Manual for CSI 2120 and Model 2120-2 Machinery Analyzers, CSI part number 97047, Rev. 5.

Overall Calculation Computation by the CSI 2100-2120 Data Collectors, Technical Note 95-00314, Emerson Process Management.

While space does not permit us to provide similar summaries for all of the numerous data collectors and other vibration measuring instruments in use today, the reader will generally be able to extrapolate similar comparisons using the information in this article and by consulting the documentation supplied with their instrumentation.

Computing RMS from Spectral Component Amplitudes

Although not used in Bently Nevada instrumentation, many portable data collection instruments employ a method for computing RMS by quadratically adding spectral line amplitudes (i.e., adding the squares and taking the square root of the sum). This is shown mathematically in equation 1

$$A_{RMS} = \sqrt{\sum_{n=1}^{k} A_n^2} \qquad [1]$$

where A_{RMS} is the RMS amplitude of the composite waveform resulting from the spectral components, *k* is the number of lines in the spectrum, and A_n is the RMS amplitude of each spectral line. Indeed, this is precisely the algorithm used by the CSI® 2120 for computing "Digital Overall" and by selected Entek®/Entek IRD® instruments for computing "FFT Overall."

Table 3 –

OVERALL WAVEFORM AMPLITUDE DETECTION OPTIONS FOR SELECTED ENTEK® AND ENTEK IRD® INSTRUMENTS

Nomenclature	Description	Comparison to Bently Nevada Instrumentation
FFT Overall	RMS x 1.414 where the RMS value is calculated by quadratically adding spectral lines, encompassing only the frequency span selected for the spectrum.	Will not agree with pk or pp readings from a Bently Nevada monitor, since it is a "derived peak" measurement.
RMS Overall	The RMS value calculated using all sampled points in the timebase waveform. Gives results closer to that of an analog RMS circuit.	Will not agree with pk or pp readings from a Bently Nevada monitor, even if scaling factor of 1.414 or 2.828 is used. May agree reasonably closely with RMS readings from a Bently Nevada monitor, depending on bandwidth settings.
Peak Overall	RMS Overall x 1.414	Will not agree with pk readings from a Bently Nevada monitor. Peak Overall ÷ 1.414 may agree reasonably closely with RMS readings from a Bently Nevada monitor, depending on bandwidth settings.
Peak-to-Peak Overall	The difference between the maximum positive-going and negative-going peaks within the time waveform for the specified sample duration.	May not agree with the pp reading from a Bently Nevada monitor depending on high-frequency content of signal, as this type of algorithm more closely resembles those used in Bently Nevada diagnostic instruments.

Sources:

Signal Processing In Continuous Monitoring Systems, P. Carle, Rockwell Automation, presented at ENTERACT International User Conference, April 19-22, 1998.

To illustrate the use of equation [1], consider the waveform of Figure 5. The mathematical representation of this waveform given by

$$f(t) = \sin(\omega t) + \sin(2\omega t + \frac{\pi}{2}) + \sin(5\omega t + \frac{\pi}{4}) \qquad [2]$$

where ω is 200π radians per second and t is in seconds.

The RMS value of this waveform can be computed using the "true RMS" method, which employs the integral of Table 1.

$$A_{RMS} = \sqrt{\frac{1}{T}\int_0^T f(t)^2 dt} = \sqrt{\frac{1}{T}\int_0^T \left[\sin(\omega t) + \sin(2\omega t + \frac{\pi}{2}) + \sin(5\omega t + \frac{\pi}{4})\right]^2 dt} \qquad [3]$$

However, since this waveform consists of only three sinusoids, it can be fully characterized by the simple 3-line spectrum shown in Figure 5. This means that equation [1] can be easily used.

Thus, noting that the pk amplitude of each spectral line is 1 and because each spectral line is a pure sinusoid with RMS amplitude pk/√2, we use Equation 1 as follows:

$$A_{RMS} = \sqrt{\sum_{n=0}^{\infty} A_n^2} = \sqrt{\sum_{n=1}^{3} A_n^2} = \sqrt{\left(\frac{A_1}{\sqrt{2}}\right)^2 + \left(\frac{A_2}{\sqrt{2}}\right)^2 + \left(\frac{A_3}{\sqrt{2}}\right)^2} = \sqrt{\left(\frac{1.0}{\sqrt{2}}\right)^2 + \left(\frac{1.0}{\sqrt{2}}\right)^2 + \left(\frac{1.0}{\sqrt{2}}\right)^2} = \sqrt{\frac{3}{2}} = 1.2247 \qquad [4]$$

This simple example was chosen because it allows the reader to better understand the inner workings of the digital algorithm. In this instance, the values computed by equation 1 and a "true RMS" circuit would be the same – equation 1 introduces no discrepancies since it uses a spectrum containing all frequencies present in the original waveform. However, in practice such situations are rare and users will generally see different results between "true RMS" and so-called "digital RMS" because the digital computation of equation [1] introduces inaccuracies in two primary ways:

A. Anti-alias filtering and/or frequency span settings may remove some high-frequency signal content. Thus, the spectrum does not faithfully represent the original waveform.

B. The spectral resolution, if too low, can "blend" discrete frequencies together.

In general, the higher the spectral resolution and the wider the spectrum bandwidth, the more accurate the digital RMS algorithm of equation [1] will be.

We have devoted a considerable portion of this article to a discussion of this "digital RMS" algorithm because it forms the basis of numerous amplitude detection options in portable data collectors. For example, consider a user of selected Entek® portable data collectors who has set their instrument to return an "FFT Overall" (see Table 3) value. The algorithm would first compute the RMS value as shown in equation [4] above. Then, it would multiply this result by 1.414 to obtain an "FFT Overall" amplitude of 1.2247 x 1.414 = 1.73. For comparison, the actual 0-pk value of the waveform in Figure 5 is 2.52, once again underscoring the complete absence of any relationship between "true peak" and "scaled RMS" readings for waveforms with more than a single sinusoid.

Key Point

We often see inquiries from users that assume the term "overall" is a type of peak reading — particularly when a factor of 1.414 is used in the computation. As pointed out earlier, this results in much confusion. Such readings are simply "scaled RMS" amplitudes and bear no relationship to actual peak readings. It does not matter how accurate (or inaccurate) the underlying RMS measurement may be — it is simply not possible to scale an RMS reading into a peak reading except in the very special case of an input signal that is a pure sinusoid.

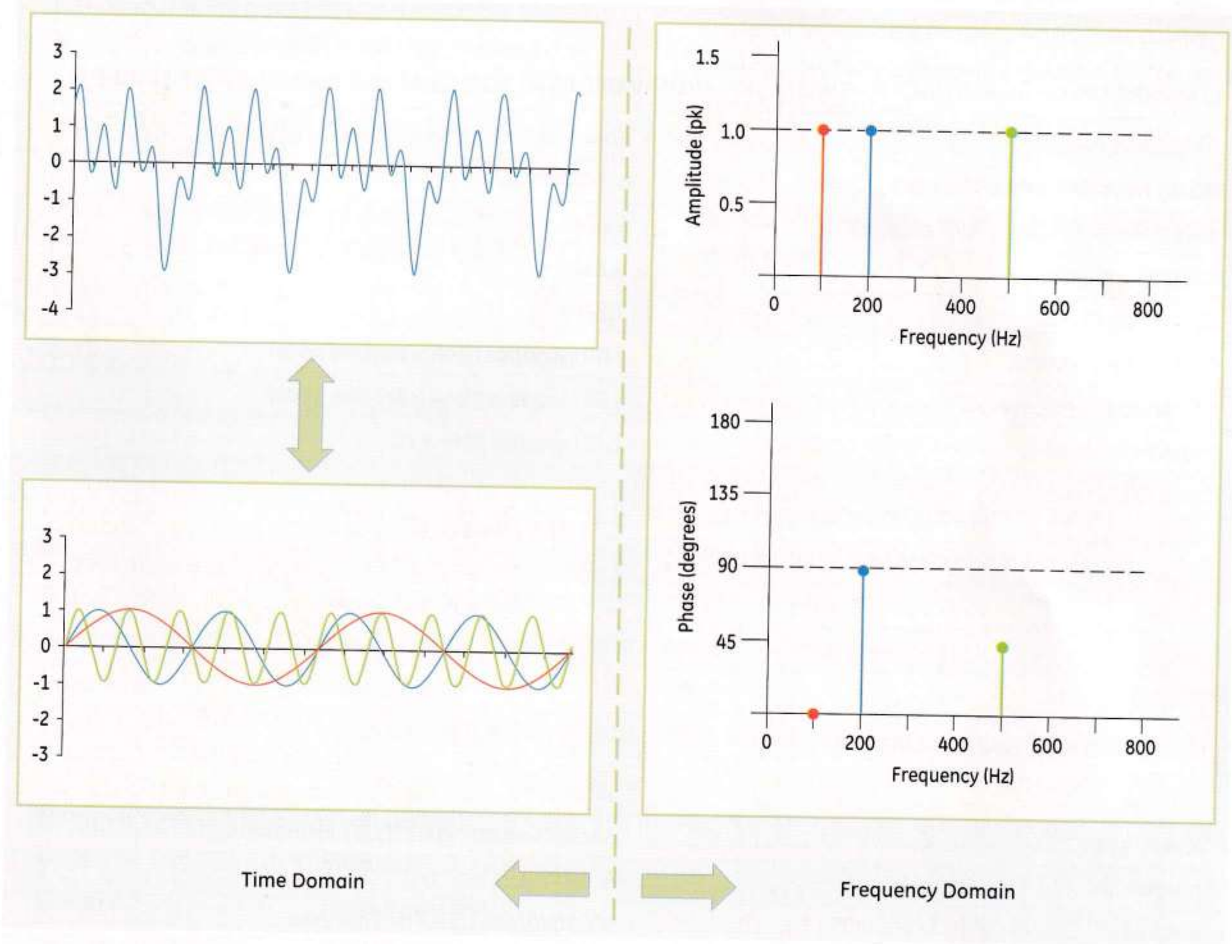


Figure 5 – Because this waveform consists of only 3 sinusoids, a spectrum with 3 lines is all that is necessary to fully characterize the wave. However, both amplitude and phase spectra are essential to properly characterize the time domain waveform. As was shown in Part 1 of this article, identical amplitude spectra can yield very different time domain waveforms if the phase relationships differ.

Table 4 summarizes the amplitudes that would be returned by various portable data collectors for the asymmetric waveform of Figure 5. It assumes the data collector frequency span fully encompasses the frequency content of the original waveform (100 Hz – 500 Hz).

As is evident from Table 4, significant discrepancies exist, even for this simple waveform consisting of only three frequencies. Users can expect a similar level of disagreement between readings when using real-world vibration signals. Also, unlike our example here, the digital and analog RMS values will rarely agree with one for the reasons previously detailed.

Case History

A user of a Bently Nevada™ 1900/27 monitor contacted us recently, complaining that the monitor did not agree with their CSI® 2120 data collector. The customer was connecting the data collector to the buffered output on the 1900/27 monitor, so the same transducer input was being used in both instruments. However, the readings were still vastly different.

Table 4 –

COMPARISON OF AMPLITUDE MEASUREMENTS FROM VARIOUS ALGORITHMS FOR WAVEFORM OF FIGURE 5

Detection Algorithm	Value
Bently Nevada monitor pk detector (pp/2)	5.05 / 2 = 2.525
Bently Nevada monitor RMS detector	1.2247
CSI digital overall	1.2247
CSI analog overall	1.2247
CSI true peak overall	3.00 (negative peak > positive peak)
CSI average peak overall	3.00 (negative peak > positive peak)
Entek FFT overall	1.73 (spectral RMS x √2)
Entek RMS overall	1.2247
Entek peak overall	1.73 (RMS overall x √2)
Entek peak-to-peak overall	5.05

Table 5 –

1900/27 CONFIGURATION SETTINGS

Options	Settings
Sensor type	Bently Nevada™ 200150 Accelerometer
Integration	Accel – to – Velocity
Sensitivity	500 mV/in/sec (19.7 mV/mm/sec)
Display	Velocity – Peak (mm/sec)
Full-Scale Range	50.8 mm/sec
Buffered Output Signal	Raw Velocity 500 mV/mm/sec (19.7 mV/mm/sec)
Buffered Output Impedance	500 Ω
Passband	8 Hz – 4kHz

To help resolve the discrepancy, we asked the customer to send us the complete configuration settings for their data collector (Table 6), allowing us to compare with the configuration settings for the 1900/27 (Table 5).

Comparing the two tables, the following discrepancies are apparent:

- The 1900/27 monitor accepts an acceleration signal and integrates this to a velocity signal. The buffered output on the 1900/27 provides this unfiltered velocity signal — NOT an acceleration signal. The CSI® data collector was incorrectly set to receive an acceleration signal and integrate this signal to velocity units. It should have been set for a velocity input without integration.
- The buffered output sensitivity of the 1900/27 was 500 mV/in/sec (or 19.7 mV/mm/sec). The data collector was correctly set for metric engineering units of mm/sec, but it incorrectly assumed an input of 0.5 V (500 mV) per engineering unit. This should have instead been 0.0197 V (19.7 mV) per engineering unit.
- The data collector was set to return a value in peak units, using the digital algorithm. It should have instead been set to return a value in peak units, using the "average peak" algorithm.

This case history is typical of many such inquiries we receive each year in that the discrepancy in readings is often due to multiple issues. In this case, and referring back to Figure 1, the issues fell into three of our four categories:

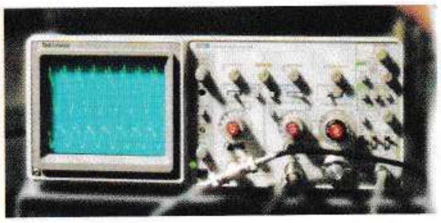
- **Category 1 — Input Discrepancies**
  The input transducer sensitivity was not set consistently across both instruments, even though the same transducer was used.
- **Category 2 — Signal Processing Discrepancies**
  The data collector was adding an additional integration stage to the signal, resulting in integrated velocity, rather than just velocity.

Table 6 –

CSI® 2120 CONFIGURATION SETTINGS

Options			**Settings**	
Acceleration:	pk-pk, Average, DB, RMS, Peak:	Digital, True Peak, Average Peak	Peak:	Digital
Velocity:	pk-pk, Average, DB, RMS, Peak:	Digital, True Peak, Average Peak	Peak:	Digital
Displacement:	pk-pk, Average, DB, RMS, Peak:	Digital, True Peak, Average Peak	Avg:	Digital
Nonstandard:	pk-pk, Average, DB, RMS, Peak:	Digital, True Peak, Average Peak	Avg:	Digital
Units Mode:	Metric, English:	CPM, Hz	Metric:	CPM
Sensor Type:	Accel, Vel, Displ, Michphn, Currnt, Flx Lf, Nonstd		Accel	
Convert to:	----, Accel, Veloc, Displ		Veloc	
Sensitivity (Sensor, V/EU):	Users Option		0.5	
Units:	Standard		Standard	
Window:	Hanning or Uniform		Hanning	
Integration Mode:	Analog or Digital		Analog	
Average Mode:	Normal or (pk Hold, Synchronous, Order-Track, Neg-VE Avrg)		Normal	
Trig Mode:	Off or (Normal, Tach, Pre-Trig, Pre-Tach)		Off	
Triax Ctrl:	Off or (Select Ch)		Off	
Input Impedance			> 125 kΩ	

Oscilloscopes Don't Lie



One of the easiest and fastest ways to settle a dispute when someone insists that one instrument is "right" and another instrument is "wrong" is to use an oscilloscope. Typically, oscilloscopes have a frequency response much higher than the signals encountered in machinery vibration analysis – sometimes into the GHz range. Likewise, they are able to measure very low frequencies accurately – all the way down to DC. This extremely broad and flat frequency response makes the oscilloscope much less prone to errors than portable vibration analyzers/collectors, which are subject to numerous configuration settings. Thus, do not make the mistake of using a portable data collector/analyzer as a substitute for an oscilloscope when conducting the steps below.

- **Step 1**
  Connect the oscilloscope to the buffered output of the monitoring system.
- **Step 2**
  Set the scope to the appropriate input sensitivity. For example, if the transducer used with the Bently Nevada monitoring system is a proximity probe, the buffered output sensitivity will typically be 200 mV/mil. Thus, setting the scope to .2V/div corresponds to 1 mil per division.
- **Step 3**
  Adjust the time scale appropriately (generally to see 3-4 complete cycles of the waveform on the screen).
- **Step 4**
  Observe the maximum positive-going and negative-going peaks. The pp value is simply the difference between the positive and negative peaks, and should agree closely with the amplitude displayed on the monitor (assuming it is a radial vibration monitor for a proximity probe, which measures pp amplitude). If the monitor has a seismic transducer as an input and is measuring pk (rather than pp) amplitude, this is simply one-half the pp value observed on the scope.

If the monitor and scope do not agree, then one of four things is usually wrong:

1. The monitor is filtering and/or integrating the signal, and this is not reflected at the buffered output.
2. The sensitivity of the buffered output (mV per engineering units) does not match the assumptions made on the scope settings. If necessary, check the transducer itself for the output sensitivity. This is generally printed on the label for seismic transducers, and on the Proximitor® sensor for Bently Nevada proximity probe systems.
3. The monitor is out of calibration.
4. The monitor is configured incorrectly.

If the monitor and scope do agree, then you can either disconnect the scope, or – if a t-connector is available – you can simultaneously connect the scope and a portable data collector/analyzer to the buffered output. If your data collector does not match the pp (or pk) amplitude displayed on the scope, then you know that your data collector is either configured incorrectly, out of calibration, or both. Remember: scopes don't lie.

As a final note, be sure to use either a real vibration signal (preferred) or a complex waveform (such as a triangle wave from a function generator) when conducting such tests. A common mistake is to introduce a pure sine wave into the monitor and data collector as the "reference signal." A pure sine wave is a special case of most of the amplitude detection algorithms and they will generally all agree closely when such an input is used. Use of a pure sinusoid is an exercise in frustration because it will often give very good agreement between instruments during the "test," but wide discrepancies will return once a "real" vibration signal is introduced. This is because a pure sinusoid is almost never representative of real-world vibration.

- **Category 3 — Amplitude Detection Algorithm Discrepancies**
  The data collector was using a peak detection algorithm that was not designed to emulate that of a Bently Nevada monitor. It should have instead used "Peak: Average Peak."

Not surprisingly, the plant was observing readings between their data collector and 1900/27 monitor that bore absolutely no resemblance to one another. After conferring with us and adjusting their data collector configuration settings, the two devices agreed much more closely with one another.

Calibration / Indication Issues

For reasons the authors have never fully understood, users seem much more inclined to believe that their permanent monitoring system is faulty than to doubt the veracity of their portable data collector. Perhaps this is because they are using their data collectors on an almost daily basis, and the monitoring panel is consulted only occasionally. However, it is not necessary to pit one device against the other. It is very rare that discrepancies are due to a fault in the instrumentation. Instead, it is frequently the case that inputs, signal processing, and amplitude algorithms are not consistent between the two instruments.

There are occasions when calibration will drift over time, leading to erroneous measurements. This was a larger problem on older analog instrumentation, particularly on those that used electro-mechanical meter movements. It is less of a problem on digital instrumentation, but can still arise — typically not because of calibration drifts, but because of incorrect configuration settings, as was shown in the case history above.

Summary

In this 2-part article we have shown that a systematic method exists for comparing the signal amplitude computed by two instruments and understanding why the readings may not agree with one another. This is most conveniently done by breaking down the analysis into the following four categories:

- Consistency of inputs
- Consistency of signal processing
- Consistency of amplitude detection algorithms
- Calibration / Indication

Differences in any one of these will lead to discrepancies in readings, and many field cases in which users have complained of disagreement between two instruments have involved inconsistencies in multiple categories. For example, the case history used in this article had discrepancies in three of the four categories. Only when these were resolved did the instruments give close agreement in readings.

One of the most common problems seen in the field is the use of amplitude detection algorithms that do not properly emulate the algorithms used in GE's Bently Nevada™ family of products. In particular, many data collectors are capable of returning values that are either scaled or un-scaled variations of RMS (Root Mean Square) amplitude measurements. This article has shown that such measurements have no correlation to the peak values typically returned by Bently Nevada monitors, except in the very special case of a pure sinusoid (which is almost never indicative of real-world vibration). In situations where RMS values are returned by the monitor, discrepancies can still exist due to differences in algorithms; however, they are often less dramatic than when users try to compare pk or pp values between instruments.

By understanding and applying the principles outlined in this article, users will be able to identify, isolate, and rectify the vast majority of discrepancies in readings between permanent monitoring systems and portable instruments.

Synopsis of Savings

Paste makes Waste

A large chemical complex along the US Gulf Coast uses GE's Bently Nevada™ continuous vibration monitoring systems and companion condition monitoring software for its critical turbo machinery. Shortly after startup of an air compressor, the vibration monitoring system tripped the unit on high vibration and temperature. Inspection of the unit found that a paste, formed by oil residue mixed with water, had plugged the oil supply ports. The ports were cleaned, the unit was restarted, and vibration and temperature returned to normal with no further problems. Had this problem gone undetected, the oil-starved bearings would have been destroyed, potentially resulting in collateral damage affecting seals and the rotor itself. At minimum, this would have required complete bearing replacements, but could have also included seal replacements and rotor refurbishment/replacement. Downtime would have been considerably longer with associated lost production costs in the millions.

The Value of Belief

During the last several years, an Eastern European customer retrofit ten of its turbine-generator installations with continuous condition monitoring systems using GE's Bently Nevada hardware and System 1® software. In total, the systems help the customer protect and manage more than 1500 MW of power production assets across six facilities.

The previous monitoring systems were responsible for numerous false trips, and fostered a climate of mistrust in the machinery instrumentation systems. Shortly after installation of the new systems, a 120 MW unit tripped based on high vibration from one of its generator bearings. The initial response by plant personnel was, not surprisingly, to doubt the veracity of the vibration monitoring system. However, after analyzing the data available from the System 1 software, the plant was able to compare the data from the casing absolute transducers responsible for the shutdown with those from the proximity probes installed on the same bearing. Evidence of a significant malfunction was confirmed from both types of transducers, and after consulting with our local services team, a fluid-induced instability was diagnosed. Based on this diagnostic, the customer's maintenance department elected to modify the oil supply for this bearing, eliminating the problem.

The onset of this malfunction was very rapid and quite severe. While the old system may have detected this high vibration and shut the unit down, it did not have the ability to capture dynamic or trend data, nor did it have the ability to correlate data from different transducers along the machine. Without the ability to diagnose root cause, the unit would have been continually restarted and tripped, resulting in intermittent production and likely machine damage. This single event more than paid for the cost of the new monitoring system.

The Cost of Disbelief

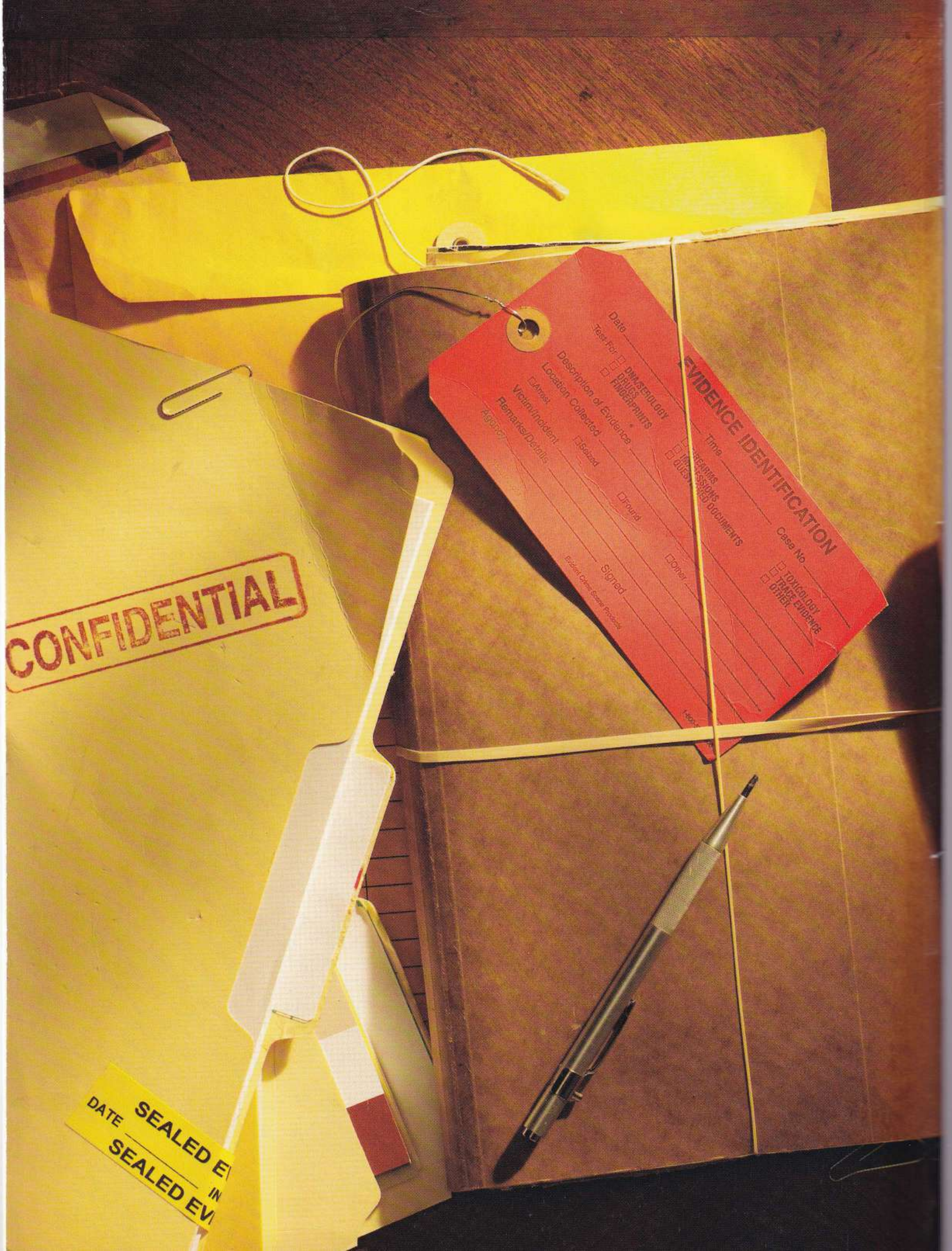
An aluminum smelter uses large, rolling element bearing fans (1 MW) to provide air to furnaces. One of the fans is fitted with a Bently Nevada 1900/27 vibration monitor. When the monitor began showing an increase in vibration, plant personnel did not trust the instrument's readings and brought in an external consultant, equipped with a hand-held vibration meter. The hand-held device used a magnetically mounted transducer, unlike the permanently affixed accelerometer used by the 1900/27 monitor. Unfortunately, because the hand-held device gave lower readings, the plant opted to ignore the higher readings given by their 1900/27 monitor and continued running the fan. Shortly thereafter, the fan wrecked and had to be removed from service for a one-week overhaul, resulting in the loss of one furnace during this time as well. Repair costs and loss of production exceeded $70,000 US. Had the monitoring system (which cost less than $2000)

been relied upon, it would have likely limited repair time and lost production to a single day rather than an entire week.

[Editor's Note: It is not uncommon for hand-held instruments to give lower readings, partly because of the less-sensitive coupling provided by magnetically mounted transducers, and sometimes because of the differences in amplitude detection algorithms used in portable instruments. See our companion article on page 40 for additional information on this topic. Also, as this scenario shows, the amount of vibration is often not as important as the fact that it changed. When a significant change occurs, the underlying cause should always be investigated.**]**

Single Save Gains Four Days of Production

A steam-turbine-driven nitrogen recycle compressor in an integrated chemical complex runs at 11,550 rpm. It is monitored with GE's Bently Nevada machinery protection systems and associated condition monitoring software. During startup, the unit encountered abnormally high vibration levels that precluded it from reaching rated speed. The unit was slowed to approximately 2000 rpm and allowed to cool, suspecting a thermal-induced rub. However, as speed was increased again the problem persisted. Assistance was enlisted from our machinery diagnostics services team, which reviewed the data collected by the online software, and they confirmed not only the presence of a rub, but the location of the rub as well. The unit was opened for inspection and, as expected, the clearance at one of the labyrinth seals was incorrect, resulting in a rub. Root cause was found to be improperly centered bolts that made the circumferential clearances unequal. Fortunately, since a spare was not available, the seal did not need to be replaced and merely needed to be re-centered. The outage lasted only two days, rather than six if the shaft or seal would have been damaged, which would have been likely if the machine had been allowed to run any longer. The unit was returned to service with no further problems. The four days of avoided lost production more than paid for the entire condition monitoring system in this single event.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